North Anna Power Station
Units 1 and 2
Application for Subsequent License Renewal

August 2020

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North Anna Power Station

Units 1 and 2

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1.0 ADMINISTRATIVE INFORMATION

1.1 GENERAL INFORMATION

1.1.1 NAME OF APPLICANTS

- Virginia Electric and Power Company (Dominion Virginia Power or Dominion), 88.4% ownership
- Old Dominion Electric Cooperative (ODEC), 11.6% ownership

1.1.2 ADDRESS OF APPLICANTS

Virginia Electric and Power Company	Old Dominion Electric Cooperative
5000 Dominion Boulevard	4201 Dominion Boulevard
Glen Allen, VA 23060	Glen Allen, VA 23060

1.1.3 DESCRIPTION OF BUSINESS OR OCCUPATION OF APPLICANT

Virginia Electric and Power Company, headquartered in Richmond, Virginia and incorporated in Virginia in 1909 as a Virginia public service corporation, is a wholly owned subsidiary of Dominion Energy, Inc. and a regulated public utility that generates, transmits, and distributes electricity for sale in Virginia and North Carolina. In Virginia, the company conducts business under the name "Dominion Energy Virginia" and primarily serves retail customers. In North Carolina, it conducts business under the name "Dominion Energy North Carolina" and serves retail customers located in the northeastern region of the state, excluding certain municipalities. In addition, Virginia Electric and Power Company sells electricity at wholesale prices to rural electric cooperatives, municipalities, and into wholesale electricity markets. All of Virginia Electric and Power Company's stock is owned by Dominion Energy, Inc.

Old Dominion Electric Cooperative (ODEC), which was incorporated under the laws of the Commonwealth of Virginia in 1948, is a not-for-profit wholesale power supply cooperative engaged in the business of providing wholesale electric service to twelve member distribution cooperatives, which in turn are engaged in the retail sale of power to member consumers located in 70 counties throughout Virginia, Delaware, Maryland, and West Virginia.

Virginia Electric and Power Company is the current licensed owner and operator of North Anna Power Station Units 1 and 2, which are the subject of this subsequent license renewal application (SLRA).

The current first renewed operating licenses will expire as follows:

- At midnight on April 1, 2038 for Unit 1 (Facility Operating License No. NPF-4).
- At midnight on August 21, 2040 for Unit 2 (Facility Operating License No. NPF-7).

Virginia Electric and Power Company will continue as the licensed owner and operator for the subsequent renewed operating licenses.

1.1.4 DESCRIPTION OF ORGANIZATION AND MANAGEMENT OF APPLICANT

Virginia Electric and Power Company is submitting this application on its own behalf and on behalf of ODEC. Otherwise, neither Virginia Electric and Power Company nor ODEC is acting as agent or representative of any other person in filing this application.

Virginia Electric and Power Company is not owned, controlled or dominated by an alien, a foreign corporation, or a foreign government. All officers and directors are citizens of the United States. The names and business addresses of Virginia Electric and Power Company's directors and officers as of August 1, 2020 are provided below:

Name	Business Address
Thomas F. Farrell, II Chairman - Chief Executive Officer	120 Tredegar Street; PH-3 Richmond, VA 23219
Robert M. Blue Director - President	600 Canal Street; 14th Floor Richmond, VA 23219
Carlos M. Brown Director - Senior Vice President, General Counsel and Chief Compliance Officer	120 Tredegar Street; PH-3 Richmond, VA 23219
James R. Chapman Executive Vice President, Chief Financial Officer and Treasurer	120 Tredegar Street; PH-3 Richmond, VA 23219
Carter M. Reid Executive Vice President, Chief of Staff and Corporate Secretary	120 Tredegar Street; PH-3 Richmond, VA 23219
Corynne S. Arnett Senior Vice President - Regulatory Affairs and Customer Experience	600 Canal Street; 14th Floor Richmond, VA 23219
Edward H. Baine Senior Vice President - Power Delivery	600 Canal Street; 14th Floor Richmond, VA 23219

Name	Business Address
Gerald T. Bischof Senior Vice President - Nuclear Operations & Fleet Performance	5000 Dominion Blvd. Glen Allen, VA 23060
Katheryn B. Curtis Senior Vice President - Generation	600 Canal Street; 18th Floor Richmond, VA 23219
William L. Murray Senior Vice President - Corporate Affairs & Communications	707 E. Main Street Richmond, VA 23219
Daniel G. Stoddard Senior Vice President and Chief Nuclear Officer	5000 Dominion Blvd. Glen Allen, VA 23060
Emil G. Avram Vice President - Business Development	600 Canal Street; 19th Floor Richmond, VA 23219
Joshua J. Bennett Vice President - Technical Services	600 Canal Street; 18th Floor Richmond, VA 23219
Michele L. Cardiff Vice President, Controller and Chief Accounting Officer	707 E. Main Street Richmond, VA 23219
Kevin J. Curtis Vice President - Transmission	10900 Nuckols Rd Glen Allen, VA 23060
Wayne L. Duman Vice President - Financial Planning & Analysis	120 Tredegar Street; PH-3 Richmond, VA 23219
Simon C. Hodges Vice President - Corporate Strategy and Chief Risk Officer	120 Tredegar Street Richmond, VA 23219
Adam S. Lee Vice President and Chief Security Officer	600 Canal Street; 9th Floor Richmond, VA 23219
Mark D. Mitchell Senior Vice President - Generation Construction	600 Canal Street; 15th Floor Richmond, VA 23219
Prabir Purohit Vice President - Finance	120 Tredegar Street, PH-3 Richmond, VA 23219

Name	Business Address
Mark D. Sartain Vice President - Nuclear Engineering & Fleet Support	5000 Dominion Blvd. Glen Allen, VA 23060
Robert W. Sauer Vice President - System Operations	600 Canal Street; 8th Floor Richmond, VA 23219
Alma W. Showalter Vice President - Tax	707 E. Main Street Richmond, VA 23219
Amanda B. Tornabene Vice President and Chief Environmental Officer	120 Tredegar Street, 4th Floor Richmond, VA 23219
Wendy T. Wellener Vice President - Shared Services	120 Tredegar Street, PH-2 Richmond, VA 23219
Charlene J. Whitfield Vice President - Distribution Operations	600 Canal Street; 14th Floor Richmond, VA 23219
Keith Windle Vice President - Financial Management	600 Canal Street; 14th Floor Richmond, VA 23219
Joseph A. Woomer Vice President - Grid & Technical Solutions	600 Canal Street; 14th Floor Richmond, VA 23219
Steve C. Wooten Vice President and Chief Information Officer	600 Canal Street; 6th Floor Richmond, VA 23219
Fred Mladen Site Vice President - North Anna Power Station	North Anna Power Station 1022 Haley Drive Mineral, VA 2311
Douglas C. Lawrence Site Vice President - Surry Power Station	Surry Power Station 5570 Hog Island Road Surry, VA 23883

ODEC is not owned, controlled or dominated by an alien, a foreign corporation, or a foreign government. All officers and directors of ODEC are citizens of the United States of America. ODEC is governed by a board of directors, consisting of two representatives from each of its Class A member distribution cooperatives, and the Board Chairman casts the vote of ODEC's one Class B member, TEC Trading, Inc.

Provided below are the names of ODEC's directors, as of August 1, 2020, whose business address is located at 4201 Dominion Boulevard, Glen Allen, Virginia 23060:

Name
John C. Lee, Jr. Vice-Chairman of the Board President & CEO, Mecklenburg Electric Cooperative
Jeffery S. Edwards Vice-Chairman of the Board, President & CEO, Southside Electric Cooperative
Michael Malandro President & CEO, Choptank Electric Cooperative
Belvin Williamson President and CEO A&N Electric Cooperative
E. Garrison Drummond A&N Electric Cooperative
Michael J. Keyser CEO & General Manager BARC Electric Cooperative
Keith L. Swisher BARC Electric Cooperative
John Burke Choptank Electric Cooperative
Steven A. Harmon President & CEO, Community Electric Cooperative
Chad Fowler Community Electric Cooperative
J. William Andrew, Jr. President & CEO, Delaware Electric Cooperative

Name
Bruce A. Henry Delaware Electric Cooperative
David J. Jones Mecklenburg Electric Cooperative
Bradley Hicks President & CEO, Northern Neck Electric Cooperative
Hunter R. Greenlaw, Jr. Northern Neck Electric Cooperative
Casey Logan President & CEO, Prince George Electric Cooperative
Paul H. Brown Prince George Electric Cooperative
Darlene H. Carpenter Rappahannock Electric Cooperative
Greg Rogers Acting CEO, Shenandoah Valley Electric Cooperative
Suzanne Obenshain Shenandoah Valley Electric Cooperative
Earl C. Currin, Jr. Southside Electric Cooperative

1.1.5 CLASS OF LICENSE, USE OF FACILITY, AND PERIOD OF TIME FOR WHICH THE LICENSE IS SOUGHT

Virginia Electric and Power Company requests renewal of the initial renewed operating licenses for a period of 20 years beyond the current expiration dates shown below to permit the continued generation and distribution of electric energy from North Anna Power Station, Units 1 and 2.

Unit	License No.	License Class	Expiration Date
1	NPF-4	104b	April 1, 2038
2	NPF-7	104b	August 21, 2040

In this SLRA, Virginia Electric and Power Company also requests renewal of the source, special nuclear material, and by-product licenses that are included within the renewed operating licenses and that were issued pursuant to 10 CFR Parts 30, 40, and 70.

1.1.6 EARLIEST AND LATEST DATES FOR ALTERATIONS, IF PROPOSED

No physical plant alterations or modifications have been identified as necessary in order to implement the provisions of this SLRA.

1.1.7 RESTRICTED DATA

With regard to the requirements of 10 CFR 54.17(f), this SLRA does not contain any "Restricted Data," as that term is defined in the Atomic Energy Act of 1954, as amended, or other defense information, and it is expected that NRC review of this request will not involve any such information.

In accordance with the requirements of 10 CFR 54.17(g), Virginia Electric and Power Company 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 Parts 25 and/or 95.

1.1.8 REGULATORY AGENCIES

The Federal Energy Regulatory Commission, Virginia State Corporation Commission and the North Carolina Utilities Commission are the principal regulators of Virginia Electric and Power Company's electric operations in Virginia and North Carolina. The contact names and addresses for these regulatory agencies are as follows:

Kimberly D. Bose, Secretary
Nathaniel J. Davis, Sr., Deputy Secretary
Federal Energy Regulatory Commission

888 First Street, NE
Washington, DC 20426

Joel H. Peck, Clerk
Virginia State Corporation Commission
1300 East Main Street
Tyler Building - First Floor
Richmond, Virginia 23219

Charlotte A. Mitchell, Chair
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

1.1.9 LOCAL NEWS PUBLICATIONS

Local news publications that circulate in the area around North Anna Power Station are as follows:

Richmond Times-Dispatch
300 E. Franklin St.
Richmond, VA 23219

Central Virginian
P.O. Box 464
Louisa, VA 23093

Daily Progress
P.O. Box 9030
Charlottesville, VA 22906

Free Lance Star
616 Amelia Street
Fredericksburg, VA 22401

1.1.10 CONFORMING CHANGES TO STANDARD INDEMNITY AGREEMENT

10 CFR 54.19(b) requires that license renewal applications include “conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license.” The current Indemnity Agreement (No. B-80) for North Anna Power Station states in Article VII that the Agreement shall terminate at the time of expiration of the license specified in Item 3 of the Attachment (to the Agreement). Item 3 of the Attachment to the Indemnity Agreement, as revised through Amendment No. 12, lists North Anna Power Station operating

license numbers NPF-4 and NPF-7. The original Indemnity Agreement and the Amendments have been reviewed. Neither Article VII nor Item 3 of the Attachment specifies an expiration date for license numbers NPF-4 and NPF-7. Therefore, no changes to the Indemnity Agreement are deemed necessary as part of this application. Should the license numbers be changed by Nuclear Regulatory Commission (NRC) upon issuance of the subsequent renewed licenses, Virginia Electric and Power Company requests that NRC amend the Indemnity Agreement to include conforming changes to Item 3 of the Attachment and other affected sections of the Agreement.

1.2 GENERAL LICENSE INFORMATION

1.2.1 APPLICATION UPDATES, RENEWED LICENSE, AND RENEWAL TERM OPERATION

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

In accordance with 10 CFR 54.21(d), Virginia Electric and Power Company will maintain a summary list in the Updated Final Safety Analysis Report (UFSAR) of activities that are required to manage the effects of aging for the systems, structures or components within the scope of license renewal during the subsequent period of extended operation and summaries of the time-limited aging analyses evaluations.

1.2.2 INCORPORATION BY REFERENCE

With the exception of the following three instances in the Environmental Report, there are no documents incorporated by reference as part of the SLRA:

- The analyses for certain impacts codified by rulemaking (61 FR 28483) for Category 1 issues
- The findings in NUREG-1437, Revision 1, for the applicable issues (Reference 1.7-19)
- The NRC findings for the 53 Category 1 issues that apply to North Anna Power Station (plus the one uncategorized issue for which the NRC came to no generic conclusion)

Other document references, either in text or in General References are listed for information only.

1.2.3 CONTACT INFORMATION

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

Mr. Daniel G. Stoddard
Senior Vice President and Chief Nuclear Officer
Virginia Electric and Power Company
Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, VA 23060-6711
(Daniel.G.Stoddard@dominionenergy.com)

with copies to:

Mr. Mark D. Sartain
Vice President - Nuclear Engineering and Fleet Support
Virginia Electric and Power Company
Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, VA 23060-6711
(Mark.Sartain@dominionenergy.com)

Mr. Fred Mladen
Site Vice President - North Anna
North Anna Power Station
1022 Haley Drive
Mineral, VA 23117
(Larry.Lane@dominionenergy.com)

Mr. B. E. Standley
Director - Nuclear Regulatory Affairs
Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, VA 23060-6711
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(Paul.Aitken@dominionenergy.com)

William S. Blair, Esq.
Senior Counsel - Nuclear
Dominion Energy Services, Inc.
120 Tredegar Street, RS-2Richmond, Virginia 23219
(Wlliam.S.Blair@dominionenergy.com)

1.3 PURPOSE

This document provides information required by 10 CFR Part 54 to support the SLRA for renewal of the initial renewed operating licenses. The SLRA contains technical information required by 10 CFR 54.21 and environmental information required by 10 CFR 54.23. The information contained herein is intended to provide the NRC with an adequate basis to make the findings required by 10 CFR 54.29.

1.4 DESCRIPTION OF THE PLANT

North Anna Power Station Units 1 and 2 are located on a site on the southern shore of Lake Anna in Louisa County, Virginia approximately 40 miles north of Richmond, Virginia. Lake Anna has been created by impounding excess waters of the North Anna River. Each unit includes a three-coolant-loop, pressurized light water reactor nuclear steam supply system, and a turbine generator furnished by Westinghouse Electric Corporation. The balance of the plant was designed and constructed by Virginia Electric and Power Company with the assistance of its agent, Stone & Webster Engineering Corporation. Each reactor unit was initially operated at a licensed power output of 2775 MWt, with a gross electrical output of approximately 947 MWe. In 1986, both units were uprated to a core power output of 2893 MWt with an expected gross electrical output of 982 MWe. Subsequently, an increase in rated thermal power from 2893 MWt to 2940 MWt was achieved in 2010 based upon increased feedwater flow measurement accuracy achieved by using high-accuracy ultrasonic flow measurement instrumentation.

Virginia Electric and Power Company also operates an independent spent fuel storage installation (ISFSI) at the site. The ISFSI operates under separate licenses issued pursuant to the provisions of 10 CFR Part 72 (Reference 1.7-1). Therefore, the ISFSI is not addressed in this application.

1.5 APPLICATION STRUCTURE

In accordance with the requirements of 10 CFR Part 54 (Reference 1.7-2), this SLRA provides the technical and environmental information required for renewal of the initial renewed operating licenses for an additional 20 years.

This SLRA is structured in accordance with Regulatory Guide 1.188, “Standard Format and Content for Applications to Renew Nuclear Plant Operating Licenses,” (Reference 1.7-5) and NEI 17-01, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal," (Reference 1.7-6). In addition, Section 3, "Aging Management Review Results," and Appendix B, "Aging Management Programs," are structured to address the guidance provided in NUREG-2192, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants," (Reference 1.7-3). NUREG-2192 references NUREG-2191, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report," (Reference 1.7-4). NUREG-2191 was used to determine the adequacy of existing programs for purposes of managing aging and which existing programs should be augmented for subsequent license renewal. The results of the aging management review, using NUREG-2191, have been documented and are illustrated in table format in Section 3, "Aging Management Review Results," of this application.

This SLRA and supporting environmental report are intended to provide sufficient information for the NRC to complete its technical and environmental reviews and enable the NRC to make the findings required by 10 CFR 54.29 in support of renewal of the initial renewed operating licenses.

The SLRA is organized into four Chapters and five Appendices as follows:

Section 1.0 - Administrative Information

Section 1.0 provides the administrative information required by 10 CFR 54.17 and 10 CFR 54.19. This section describes the plant and states the purpose for this application. Included in this chapter are the names, addresses, business descriptions, organization, and management descriptions of the applicant, as well as other administrative information. Also provided is an overview of the structure of the SLRA and a listing of acronyms and general references used throughout the SLRA.

Section 2.0 - Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review and Implementation Results

Section 2.0 describes and justifies the methods used in the integrated plant assessment to identify those structures and components subject to an aging management review 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 scoping results for systems and structures are described in Section 2.0. Scoping results are presented in Section 2.2, Table 2.2-1. Screening results are presented in Sections 2.3, 2.4, and 2.5.

The screening results consist of lists of component types that require aging management review (AMR). Descriptions of mechanical systems and structures within the scope of license renewal are provided as background information. The descriptions of systems identify subsequent license renewal (SLR) drawings that document the in-scope mechanical components. The SLR drawings are provided in a separate submittal. For each in-scope system and structure, component types requiring an aging management review are identified, associated component intended functions are identified, and the appropriate reference to the Section 3.0 Table providing the AMR results is provided.

Selected structural and electrical component types, such as component supports and cables, were evaluated as commodities. Under the commodity approach, selected structural and electrical component types were evaluated based upon common environments and materials. For each of these commodities, the component types requiring aging management review are presented in Sections 2.4, and 2.5.

Section 3.0 - Aging Management Review

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 current licensing basis throughout the subsequent period of extended operation. Section 3.0 presents the results of the AMRs. Section 3.0 is the link between the scoping and screening results provided in Section 2.0 and the aging management programs (AMPs) described in Appendix B.

AMR results are presented in tabular form, in a format in accordance with the Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants, SRP-2192. For mechanical systems, aging management review results are provided in Sections 3.1, 3.2, 3.3, and 3.4 for the reactor vessel, reactor vessel internals, and reactor coolant system; engineered safety features; auxiliary systems; and steam and power conversion systems, respectively. AMR results for Containment, structures, and component supports are provided in Section 3.5. AMR results for electrical and instrumentation and controls are provided in Section 3.6.

Section 4.0 - Time-Limited Aging Analyses

Time-limited aging analyses (TLAAs), as defined by 10 CFR 54.3, are listed in this section. Section 4.0 includes each of the TLAAs identified in SRP-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: (1) each of the analyses remains valid for the subsequent period of extended operation, (2) the analyses have been projected to the end of the subsequent period of extended operation, or (3) the effects of aging on the intended function(s) will be adequately managed for the subsequent period of extended operation.

Section 4.0 also confirms that plant-specific exemptions granted pursuant to 10 CFR 50.12 were identified that are based upon a TLAA, as defined in 10 CFR 54.3. Therefore, no further evaluation is required for plant-specific exemptions granted pursuant to 10 CFR 50.12.

Appendix A - UFSAR Supplement

The Updated Final Safety Analysis Report (UFSAR) supplement is found in Appendix A and contains a summary of aging management programs credited for managing the effects of aging for the subsequent period of extended operation. In addition, summary descriptions and dispositions of TLAA evaluations and a summary of subsequent license renewal commitments are provided. The subsequent license renewal commitments are identified in Table A4.0-1, Subsequent License Renewal Commitments. The information in Appendix A fulfills the requirements in 10 CFR 54.21(d).

Appendix B - Aging Management Programs

Appendix B describes the programs that are credited for managing aging effects for components and structures during the subsequent period of extended operation based upon the AMR results provided in Section 3.0 and the TLAA results provided in Section 4.0. The information in Section 2.0, Section 3.0, and Appendix B fulfills the requirements of 10 CFR 54.21(a).

Appendix C - Not Used

Appendix D - Technical Specification Changes

Appendix D satisfies the requirements of 10 CFR 54.22 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. Since no Technical Specification changes are requested, this Appendix is not used.

Appendix E - Environmental Information

Appendix E satisfies the requirements of 10 CFR 54.23 to provide a supplement to the Environmental Report that complies with the requirements of subpart A of 10 CFR Part 51 (Reference 1.7-12).

1.6 ACRONYMS

Table 1.6-1 Acronyms

Acronym	Definition
AAC	Alternate Alternating Current
AC	Alternating Current
ACAR	Aluminum Conductor Aluminum Reinforced
ACI	American Concrete Institute
ACSR	Aluminum Conductor Steel Reinforced
AEC	Atomic Energy Commission
AFW	Auxiliary Feedwater
ALE	Adverse Localized Environments
AMA	Aging Management Activity
AMP	Aging Management Program
AMR	Aging Management Review
AMSAC	ATWS Mitigation System Actuation Circuit
ANSI	American National Standards Institute
API	American Petroleum Institute
AS	Auxiliary Steam

Table 1.6-1 Acronyms

Acronym	Definition
ASCO	Automatic Switch Company
ASME	American Society of Mechanical Engineers
ASR	Alkali-Silica Reaction
ASTM	American Society for Testing and Materials
ATWS	Anticipated Transients Without SCRAM
AVB	Anti-Vibration Bar
B&W	Babcock and Wilcox
BC	Bearing Cooling
BD	Blowdown
BIW	Boston Insulated Wire
BMI	Bottom Mounted Instrumentation
BR	Boron Recovery
BTP	Branch Technical Position
CAS	Central Alarm Station
CASS	Cast Austenitic Stainless Steel

Table 1.6-1 Acronyms

Acronym	Definition
CAT	Chemical Addition Tank
CC	Component Cooling
CCHX	Component Cooling Heat Exchanger
CCVT	Captive Coupled Voltage Transformer
CD	Chilled Water
CD-ROM	Compact Disk-Read only Memory
CEI	Chemistry Effectiveness Indicator
CFR	Code of Federal Regulations
CFRP	Carbon Fiber Reinforced Polymer
CH	Chemical Volume and Control
CISIs	Containment Inservice Inspections
CLB	Current Licensing Basis
CN	Condensate
CP	Condensate Polishing
CP	Cathodic Protection

Table 1.6-1 Acronyms

Acronym	Definition
CR	Condition Report
CRDM	Control Rod Drive Mechanism
CRGT	Control Rod Guide Tube
CrMo	Chromium-Molybdenum
CS	Containment Spray
CSA	Conductor Seal Assembly
CSPE	Chlorosulfonated Polyethylene
Cu-Ni	Copper Nickel
CUF	Cumulative Usage Factor
CV	Containment Vacuum
CvUSE	Charpy Upper Shelf Energy
CW	Circulating Water
DA	Degradation Assessments
DA	Drains-Aerated
DB	Drains-Building Services

Table 1.6-1 Acronyms

Acronym	Definition
DBE	Design Basis Event
DC	Direct Current
DCP	Design Change Package
DG	Drains-Gaseous
DGSS	Diesel Generator Support Systems
DLPS	Drains and Liquid Processing Systems
EAF	Environmentally Assisted Fatigue
ECCS	Emergency Core Cooling Systems
ECMT	Emergency Condensate Makeup Tank
ECSA	Electrical Conductor Seal Assembly
ECST	Emergency Condensate Storage Tank
ECT	Eddy Current Testing
EDG	Emergency Diesel Generator
EDS	Equipment Data System
EFPY	Effective Full-Power Years

Table 1.6-1 Acronyms

Acronym	Definition
EHC	Electro-hydraulic Control
EPDM	Ethylene Propylene Diene Monomer
EPR	Ethylene Propylene Rubber
EPRI	Electric Power Research Institute
EQ	Environmental Qualification
EQML	Equipment Qualification Master List
ESF	Engineered Safety Features
ESGR	Emergency Switchgear Room
ESW	Emergency Service Water
ESWPH	Emergency Service Water Pump House
ET	Eddy Current Test
ETA	Ethanolamine
EVT	Enhanced Visual Test
FAC	Flow Accelerated Corrosion
FAO	Free Available Oxidant

Table 1.6-1 Acronyms

Acronym	Definition
FC	Fuel Pit Cooling
FCG	Fatigue Crack Growth
FME	Foreign Materials Exclusion
FMECA	Failure Modes, Effects, and Criticality Analysis
FMR	Flame and Moisture Resistant
FP	Fire Protection
FPSS	Fire Protection and Supporting Systems
FRP	Fiberglass Reinforced Plastic
FSAR	Final Safety Analysis Report
FSER	Final Safety Evaluation Report
FW	Feedwater
FWST	Fire Water Storage Tank
GALL-SLR	Generic Aging Lessons Learned for Subsequent License Renewal
GDC	General Design Criterion
GE	General Electric

Table 1.6-1 Acronyms

Acronym	Definition
GL	Generic Letter
HELB	High-Energy Line Break
HG	Hydrogen Gas
HHSI	High-Head Safety Injection
HLIS	High-Level Intake Structure
HMWPE	High Molecular Weight Polyethylene
HRSS	High Radiation Sampling System
HV	Heating and Ventilation
HVAC	Heating, Ventilation, and Air Conditioning
HVT	High-Voltage Termination
I&C	Instrumentation and Controls
IA	Instrument Air
IARC	Interim Alternate Repair Criteria
IASCC	Irradiation-Assisted Stress Corrosion Cracking
IC	Incore Instrumentation

Table 1.6-1 Acronyms

Acronym	Definition
ICCS	Inadequate Core Cooling System
ICES	INPO Consolidated Event System
ID	Inner Diameter
IE	Inspection and Enforcement
IE	Irradiation Embrittlement
IEB	Inspection and Enforcement Bulletin
IEN	Inspection and Enforcement Notice
IGSCC	Intergranular Stress Corrosion Cracking
ILRT	Integrated Leak Rate Test
IN	Information Notice
INEL	Idaho National Engineering Laboratories
INPO	Institute of Nuclear Power Operations
IPA	Integrated Plant Assessment
IR	Insulation Resistance
ISR/IC	Irradiation-Induced Stress Relaxation and Creep

Table 1.6-1 Acronyms

Acronym	Definition
ISFSI	Independent Spent Fuel Storage Installation
ISG	Interim Staff Guidance
ISI	Inservice Inspection
ISRS	Inside Recirculation Spray
ITG	Issues Task Group
Ksi	Kilo-pounds per square inch
LAR	License Amendment Request
LAW	Lower Axial Weld
LBB	Leak-Before-Break
LCMP	Life Cycle Management Program
LFET	Low Frequency Electromagnetic Examination Techniques
LFW	Lower Flange Weld
LGW	Lower Girth Weld
LHSI	Low-Head Safety Injection
LLIS	Low-Level Intake Structure

Table 1.6-1 Acronyms

Acronym	Definition
LLRT	Local Leak Rate Test
LM	Leakage Monitoring
LOCA	Loss-of-Coolant Accident
LP	Liquid penetrant
LR	License Renewal
LRA	License Renewal Application
LTOPS	Low Temperature Overpressure Protection System
LW	Liquid and Solid Waste
MAW	Middle Axial Weld
MCR	Main Control Room
MEB	Metal Enclosed Bus
MIC	Microbiologically Influenced Corrosion
MIRVSP	Master Integrated Reactor Vessel Surveillance Program
MOV	Motor Operated Valve
MPs	Megapascals

Table 1.6-1 Acronyms

Acronym	Definition
MRP	Material Reliability Program
MS	Main Steam
MUR	Measurement Uncertainty Recapture
MWe	Megawatt-electric
MWt	Megawatt-thermal
NACE	National Association of Corrosion Engineers
NAPS	North Anna Power Station
NDE	Non-destructive Examination
NEI	Nuclear Energy Institute
NFPA	National Fire Protection Association
NI	Nuclear Instrumentation
NPS	Nominal Pipe Size
NRC	U.S. Nuclear Regulatory Commission
NSAC	Nuclear Safety Analysis Center
NSSS	Nuclear Steam Supply System

Table 1.6-1 Acronyms

Acronym	Definition
NST	Neutron Shield Tank
OCCWS	Open Cycle Cooling Water System
OE	Operating Experience
OOS	Out of Specification
OSRS	Outside Recirculation Spray
P-T	Pressure-Temperature
PAG	Predictive Analysis Group
PDI	Performance Demonstration Initiative
PEO	Period of Extended Operation
PG	Primary Grade
PI	Polarization Index
PM	Preventive Maintenance
PORV	Power Operated Relief Valve
PT	Penetrant Testing
PTS	Pressurized Thermal Shock

Table 1.6-1 Acronyms

Acronym	Definition
PU	Power Uprate
PWR	Pressurized Water Reactor
PWROG	Pressurized Water Reactor Owners Group
PWSCC	Primary Water Stress Corrosion Cracking
QA	Quality Assurance
QDR	Qualification Documentation Report
QS	Quench Spray
RAI	Request for Additional Information
RC	Reactor Coolant
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RCSC	Research Council for Structural Corrections
RFO	Refueling Outage
RG	Regulatory Guide
RH	Residual Heat Removal

Table 1.6-1 Acronyms

Acronym	Definition
RM	Radiation Monitoring
RO	Restricting Orifice
RS	Recirculation Spray
RSST	Reserve Station Service Transformer
RTD	Resistance Temperature Devices
RT_{NDT}	Reference nil ductility transition temperature
RT_{PTS}	Reference temperature for pressurized thermal shock
RV	Reactor Vessel
RVI	Reactor Vessel Internals
RVLIS	Reactor Vessel Level Instrumentation System
RVWG	Reactor Vessel Working Group
RWST	Refueling Water Storage Tank
SA	Service Air
SBO	Station Blackout
SC	Structures and Components

Table 1.6-1 Acronyms

Acronym	Definition
SCC	Stress Corrosion Cracking
SCC-W	Stress Corrosion Cracking at a Weld
SCS	Secondary Core Support
SD	Steam Drains
SDBD	System Design Basis Document
SER	Safety Evaluation Report
SFP	Spent Fuel Pool
SG	Steam Generator
SI	Safety Injection
SLR	Subsequent License Renewal
SLRA	Subsequent License Renewal Application
SOV	Solenoid Operated Valve
SPCS	Steam and Power Conversion Systems
SPS	Surry Power Station
SR	Silicone Rubber

Table 1.6-1 Acronyms

Acronym	Definition
SRF	Surry Repair Facility
SRP	Standard Review Plan
SS	Sampling System
SSCs	Systems, Structures, and Components
SST	Station Service Transformer
SW	Service Water
TE	Thermal Embrittlement
T.S.	Technical Specification
TGSCC	Transgranular Stress Corrosion Cracking
TLAA	Time-Limited Aging Analyses
TR	Technical Report
UAW	Upper Axial Weld
UFSAR	Updated Final Safety Analysis Report
UFW	Upper Flange Weld
UGW	Upper Girth Weld

Table 1.6-1 Acronyms

Acronym	Definition
UPTI	Underground Piping and Tanks Initiative
USE	Upper Shelf Energy
UT	Ultrasonic / Ultrasonic Testing
VCT	Volume Control Tanks
VHP	Vessel Head Penetration
VS	Void Swelling
VT	Visual Test
WCP	Work Control Process
WOG	Westinghouse Owners' Group
XLPE	Cross-linked Polyethylene

1.7 GENERAL REFERENCES

1.7-1 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."

1.7-2 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants."

1.7-3 NUREG-2192, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants."

1.7-4 NUREG-2191, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report."

1.7-5 Regulatory Guide 1.188, "Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses."

1.7-6 NEI 17-01, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal," December 2017.

1.7-7 10 CFR 50.48, "Fire Protection."

1.7-8 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants."

1.7-9 10 CFR 50.62, "Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants."

1.7-10 10 CFR 50.63, "Loss of All Alternating Current Power."

1.7-11 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."

1.7-12 10 CFR 51, "Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions."

1.7-13 NUREG-0933, "Resolution of Generic Safety Issues," U.S. Nuclear Regulatory Commission, Supplement 34, December 2011.

1.7-14 ANSI/ANS-51.1-1983, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants."

1.7-15 10 CFR 50.61, “Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events.”

1.7-16 10 CFR 50, “Domestic Licensing of Production and Utilization Facilities.”

1.7-17 North Anna Power Station Units 1 and 2 Technical Specifications, Change 58

1.7-18 North Anna Power Station Updated Final Safety Analysis Report (UFSAR), Revision 55

1.7-19 NUREG-1437, “Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants, US NRC, Revision 1, 2013.

2.0 SCOPING AND SCREENING METHODOLOGY FOR IDENTIFYING STRUCTURES AND COMPONENTS SUBJECT TO AGING MANAGEMENT REVIEW AND IMPLEMENTATION RESULTS

This section describes the process for identifying structures and components subject to aging management review (AMR) in the North Anna Power Station (NAPS) 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 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 NAPS 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 (Reference 1.7-6). 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 and component supports

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 at NAPS. Subsequent sections provide details on how the process was implemented.

The initial step in the scoping process was to define the entire plant in terms of systems and structures. Each of these identified plant systems and structures were evaluated against the scoping criteria in 10 CFR 54.4(a)(1), (a)(2), and (a)(3), to determine if the system or structure performs or supports a safety-related intended function, if the system or structure failure could prevent the satisfactory accomplishment of a safety-related function, or if the system or structure performs functions that demonstrate compliance with the requirements of one of the five subsequent license renewal regulated events. The intended function(s) that are the bases for including systems and structures within the scope of subsequent license renewal were also identified.

Systems that contain mechanical components such as pumps, piping, valves, etc., are addressed as mechanical systems. A mechanical system was included within the scope of subsequent license renewal if any portion of the system met the scoping criteria in 10 CFR 54.4(a)(1), (a)(2), or (a)(3). Mechanical systems determined to be within the scope of subsequent license renewal were then further evaluated to determine those system components that are required to perform or support the identified system intended function(s). The in-scope boundaries of mechanical systems were identified and are described in Section 2.3. These boundaries are also depicted on the subsequent license renewal boundary drawings. Additional details on scoping evaluations and boundary drawing development are provided in Section 2.1.4.5.

A structure was included within the scope of subsequent license renewal if any portion of the structure met the scoping criteria in 10 CFR 54.4(a)(1), (a)(2), or (a)(3). Structures 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 within the scope of subsequent license renewal that are required to perform or support the identified structure intended function(s) were identified and are described in Section 2.4. Site plan drawings identify depicted structures that are within the scope of subsequent license renewal. Additional details on scoping evaluations and boundary drawing development are provided in Section 2.1.4.5.

Systems that contain Electrical and Instrumentation and Control (I&C) components, but do not contain mechanical components, are addressed as electrical and I&C systems. Electrical and I&C systems were included within the scope of subsequent license renewal if any portion of the system met the scoping criteria in 10 CFR 54.4(a)(1), (a)(2), or (a)(3). Electrical and I&C components within the in-scope electrical and I&C systems were included within the scope of subsequent license renewal. Likewise, electrical and I&C components within in-scope mechanical systems were included within the scope of subsequent license renewal. Additional details on electrical and I&C system scoping are provided in Section 2.1.4.5.

After completion of the scoping, the screening process was performed to evaluate the structures and components within the scope of subsequent license renewal to identify the long-lived and passive structures and components subject to Aging Management Review (AMR). In addition, the passive intended functions of structures and components subject to AMR were identified. Additional details on the screening process are provided in Section 2.1.5.

Selected components, such as equipment supports, structural items (e.g., fire barriers), and passive electrical components, were scoped and screened as commodities. As such, they were not evaluated with the individual system or structure, but were evaluated collectively as a commodity group. Commodity groups utilized are consistent with NUREG-2192, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants" (Reference 1.7-3), Table 2.1-6, and previous license renewal applications accepted by the NRC.

2.1.2 INFORMATION SOURCES USED FOR SCOPING AND SCREENING

A number of different current licensing basis (CLB) and design basis information sources were utilized in the scoping and screening process. The NAPS CLB is consistent with the definition provided in 10 CFR 54.3. The CLB includes NRC regulations and appendices thereto; orders; license conditions; exemptions; and technical specifications. It also includes the plant-specific design-basis information defined in 10 CFR 50.2 as documented in the most recent UFSAR as required by 10 CFR 50.71 and the commitments remaining in effect that were made in docketed licensing correspondence such as responses to NRC bulletins, generic letters, and enforcement actions, as well as commitments documented in NRC safety evaluations or licensee event reports. The significant source documentation is discussed below.

These source documents are available in hard copy or electronic format. Document records such as licensing correspondence and NRC Safety Evaluation Reports are available in a searchable database, such that applicable documents can be identified and located by searching the appropriate topic.

2.1.2.1 Updated Final Safety Analysis Report

There is a common Updated Final Safety Analysis Report (UFSAR) for NAPS. The UFSAR is updated regularly in accordance with the requirements of 10 CFR 50.71(e). The UFSAR provided significant input for system and structure descriptions and functions.

2.1.2.2 Engineering Drawings

Engineering drawings at NAPS provide system, structure, and component configuration details. These drawings were utilized to determine SSC functional requirements, safety classification, environments, materials of construction, etc., in support of scoping, screening and aging management review evaluations.

2.1.2.3 Controlled Plant Component Database

The controlled NAPS equipment database is contained within the Plant Asset Management System (PAMS). PAMS provides a comprehensive listing of plant components with controlled fields for unique equipment tag numbers, system designation, environmental qualification (EQ) designation and safety classification. It also provides uncontrolled component details such as plant location and material information or references.

2.1.2.4 Fire Protection Report

There is a common Fire Protection (Appendix R) Report for NAPS. The NAPS Fire Protection (Appendix R) Report describes the fire protection configuration for the confinement, detection, and suppression of fires, and demonstrates the capability to achieve and maintain safe shutdown conditions in the event of a fire, in support of the Fire Protection Program functions.

2.1.2.5 Maintenance Rule System Basis Database

The maintenance rule system basis database documents the results of maintenance rule scoping for NAPS systems and structures. The maintenance rule database provided an additional source of information to identify system and structure functions.

2.1.2.6 Environmental Qualification Master List

Electrical equipment and components that must be environmentally qualified are identified in PAMS. The PAMS equipment database is discussed in Section 2.1.2.3. The database includes a listing of equipment and components, and includes fields that identify specific equipment information including a controlled field for environmental qualification level.

2.1.2.7 Other CLB References

- Application for Renewed Operating Licenses, North Anna Power Station Units 1 and 2 (Initial LRA)
- NUREG-1766, Safety Evaluation Report Related to the License Renewal of North Anna North Anna Power Station, Units 1 and 2, and Surry Power Station, Units 1 and 2
- NRC Safety Evaluation Reports (SERs) include NRC staff review of NAPS licensing submittals. Some of these documents may contain licensee commitments.
- Engineering evaluations and calculations can provide additional information about the requirements or characteristics associated with the evaluated systems, structures, or components.
- Licensing Correspondence includes 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.

2.1.2.8 Site Walkdowns

Walkdowns were performed to confirm the configuration and material properties of plant systems, structures, and components where that information was not available from plant documentation.

2.1.3 TECHNICAL BASIS DOCUMENTS

Technical basis documents were prepared in support of the subsequent license renewal project. Engineers experienced in nuclear plant systems, programs, and operations prepared the technical basis documents. Technical basis documents contain technical evaluations and bases for decisions or positions associated with subsequent license renewal requirements as described below. Technical basis documents are prepared, reviewed, and approved in accordance with project procedures, and are based on the CLB source documents described in Section 2.1.2.

The following sections describe the technical basis documents associated with the NAPS scoping and screening methodology.

2.1.3.1 Subsequent License Renewal Systems and Structures List

A comprehensive list of systems and structures was identified to be evaluated for subsequent license renewal scoping. While there exists a variety of document sources that identify and list systems and structures at NAPS, no single source provided the comprehensive list in a format appropriate for 10 CFR 54.4 subsequent license renewal system and structure scoping. Therefore, a technical basis document was prepared to establish a comprehensive list of subsequent license renewal systems and structures, and to document the basis for the list. Starting with the systems and structures list derived from the PAMS equipment database, the list was evaluated against the

NAPS UFSAR, plant design drawings, the maintenance rule database, and other plant CLB documents. Plant systems and structures were arranged into logical groupings for scoping reviews, and the groupings were defined as subsequent license renewal systems, structures and commodity groups. The technical basis document assures plant structures and components included in the scoping review are associated with a system, structure, or commodity group.

The technical basis document grouped subsequent license renewal systems and structures into the following categories:

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

This grouping of the NAPS subsequent license renewal systems and structures is based on the NAPS UFSAR and the guidance of NUREG-2191 “Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report,” Final Report (Reference 1.7-4). The complete list of systems, structures, and commodity groups evaluated for subsequent license renewal is provided in Section 2.2 of this application.

2.1.3.2 Identification of Safety-Related Systems and Structures

Safety-related systems and structures are included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(1) scoping criterion. NAPS plant components that have been classified as safety-related are identified as “SR” in the controlled safety classification data field in PAMS. NAPS safety-related functions described in the UFSAR were evaluated against system functions to confirm the PAMS safety-related classification. NAPS safety classification procedures were reviewed against the subsequent license renewal safety-related scoping criterion in 10 CFR 54.4(a)(1) to confirm that NAPS safety-related classification is consistent with subsequent license renewal requirements.

The NAPS definition of safety-related is as follows:

Safety-related structures, systems and components that are relied upon to remain functional during and following design basis events to ensure:

- T*he 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 exposure comparable to the guidelines in Sec. 50.34(a)(1), 50.67(b)(2) or 100.11, as applicable.*

This definition is equivalent to 10 CFR 54.4(a)(1) for the purposes of subsequent license renewal scoping. The wording difference is addressed as follows:

Design Basis Events

The NAPS definition of safety-related does not reference 10 CFR 50.49(b)(1) to define design basis events (DBEs). However, the NAPS definition of design basis events is:

Those events that establish the conditions for which the plant is designed. DBEs include the following:

- *Normal operation*
- *Anticipated operational occurrences/transients*
- *Design basis accidents*
- *External events*
- *Natural phenomena*

This definition corresponds to that provided in 10 CFR 50.49(b)(1).

Therefore, the NAPS definition of safety-related is consistent with 10 CFR 54.4(a)(1) and results in a comprehensive list of safety-related systems and structures that were included within the scope of subsequent license renewal and documented in a technical basis document. This is consistent with NUREG-2192, Section 2.1.3.1.1. Additional detail on the application of the 10 CFR 54.4(a)(1) scoping criterion is provided in Section 2.1.4.1.

2.1.3.3 10 CFR 54.4(a)(2) – Nonsafety-Related Affecting Safety-Related

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) were included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(2) requirements. A technical basis document was prepared to ensure complete and consistent application of this scoping criterion.

This subsequent license renewal scoping criteria requires consideration of the following:

- Nonsafety-related SSCs required to provide functional support for a safety-related 10 CFR 54.4(a)(1) function.
- Nonsafety-related systems directly connected to and providing structural support for a safety-related SSC.
- Nonsafety-related systems with a potential for spatial interaction with safety-related SSCs.

The first item is addressed by reviewing the NAPS UFSAR and other CLB documents to identify nonsafety-related systems or structures required to support satisfactory accomplishment of a safety-related function. SSCs required for the system to perform its support function are included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(2). The remaining two items concern nonsafety-related systems with potential physical or spatial interaction with safety-related systems, structures, and components. Scoping of these systems is the subject of NEI 95-10, Appendix F (as referenced by NEI 17-01). To assure complete and consistent application of 10 CFR 54.4(a)(2) requirements and NEI 95-10, the technical basis document included a review of the CLB references relevant to physical or spatial interactions and describes the NAPS approach to scoping of nonsafety-related systems with a potential for physical or spatial interaction with safety-related SSCs. NAPS chose to implement the preventive option as described in NEI 95-10 Appendix F (as referenced by NEI 17-01). The technical basis document provides guidance to ensure that subsequent license renewal scoping for 10 CFR 54.4(a)(2) met the requirements of the license renewal rule and NEI 17-01. Additional detail on the application of the 10 CFR 54.4(a)(2) scoping criterion is provided in Section 2.1.4.2.

2.1.3.4 10 CFR 54.4(a)(3) – Regulated Events

10 CFR 54.4(a)(3) requires that plant SSCs within the scope of subsequent license renewal include SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the 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). Technical basis documents were prepared to address subsequent license renewal scoping of SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission’s regulations for fire protection, environmental qualification, anticipated transients without scram, station blackout, and pressurized thermal shock. CLB documents were evaluated to identify the systems and structures that are relied upon to demonstrate compliance with each of these regulations. These technical basis documents are summarized below:

Fire Protection

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 subsequent license renewal.

The scope of systems and structures required for the fire protection program 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 suppression
- Systems and structures required to meet commitments made to Appendix A of Branch Technical Position (BTP) APCSB 9.5-1

UFSAR, Section 9.5.1.1 confirms that NAPS satisfies the regulatory criteria set forth in General Design Criterion 3, in 10 CFR 50 Appendix R (Sections III.G, III.J, and III.O), and in Appendix A to Branch Technical Position APCSB 9.5-1. The fire protection program for NAPS has been found, in NRC Safety Evaluation Reports, to satisfy the regulatory criteria set forth in these documents. Fire protection system and structure scoping for NAPS is performed consistent with this guidance, and is documented in the technical basis document.

The fire protection technical basis document summarizes results of a detailed review of the plant's fire protection program documents that demonstrate compliance with the requirements of 10 CFR 50.48. The technical basis document provides a list of systems and structures credited in the plant's fire protection program documents. For the listed systems and structures, the technical basis document also identifies appropriate CLB references. The identified systems and structures are included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(3) scoping criteria.

The fire detection and suppression systems at NAPS are plant-wide systems that protect a wide variety of plant equipment. The portions of these systems that are not required to demonstrate compliance with 10 CFR 50.48 are identified in the UFSAR. Those portions are not included within the scope of subsequent license renewal if (1) those portions of the system are provided to protect areas that do not contain any SSCs within the scope of subsequent license renewal and (2) those portions of the system can be isolated from the in-scope portions of the system. The portions of the fire suppression and detection systems that are included within the scope of subsequent license renewal are identified in the technical basis document. Those portions of fire detection and suppression systems that are attached to in-scope portions of the system, but not included in scope, can be isolated from the in-scope portion of the system by closing the associated isolation valve. The isolation valve is included within the scope of subsequent license renewal.

Environmental Qualification

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 environmental qualification (10 CFR 50.49) be included within the scope of subsequent license renewal.

10 CFR 50.49 defines electric equipment important to safety that is required to be environmentally qualified to mitigate certain accidents that would result in harsh environmental conditions in the plant. The EQ program, which satisfies these requirements, controls the maintenance of the list of EQ components. The PAMS component database contains a controlled field that identifies components within the EQ program.

The EQ technical basis document provides a list of systems that include EQ components. These systems are included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(3).

Pressurized Thermal Shock

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 pressurized thermal shock (10 CFR 50.61) be included within the scope of subsequent license renewal.

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 CLB shows that the NAPS reactor vessel has been demonstrated to meet the toughness requirements of 10 CFR 50.61 through its current 60-year end-of-license period. Eighty-year end-of-license fluence projections were prepared, and the components that are projected to meet the definition of beltline material after this time were identified.

The PTS technical basis document summarizes the results of a review of the NAPS current licensing basis with respect to pressurized thermal shock. The reactor vessel is included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(3) scoping criteria.

Anticipated Transients Without Scram

Criterion 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 anticipated transients without scram (10 CFR 50.62) be included within the scope of subsequent license renewal.

An anticipated transient without scram is an anticipated operational occurrence that is accompanied by a failure of the reactor trip function to shut down the reactor. The Anticipated Transients Without Scram (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.

ATWS design criteria are described in UFSAR, Section 7.7.1.14, Anticipated Transient Without Scram (ATWS) Mitigation System Description. The ATWS Mitigation System Actuation Circuitry (AMSAC) consists of a diverse method to mitigate the consequences of an ATWS event by isolating steam generator blowdown, initiating the auxiliary feedwater system, initiating a turbine trip, and tripping the rod control system motor-generator sets to shut down the reactor under conditions indicative of an ATWS.

The NAPS ATWS technical basis document summarizes the AMSAC and includes a list of systems and structures associated with AMSAC. SSCs classified as satisfying criterion 10 CFR 54.4(a)(3) related to ATWS are included within the scope of subsequent license renewal.

Station Blackout

Criterion 10 CFR 54.4(a)(3) requires that SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the regulations for station blackout (10 CFR 50.63) be included within the scope of subsequent license renewal.

10 CFR 50.63 requires that each light-water-cooled nuclear power plant be able to withstand, for a specified duration, and recover from a station blackout (SBO). An SBO is the loss of offsite and onsite AC electric power to the essential and nonessential switchgear buses in a nuclear power plant. SBO does not include the loss of available AC power to buses fed by station batteries through inverters or by alternate AC sources.

The objective of this requirement is to assure that nuclear power plants are capable of withstanding an SBO and maintaining adequate reactor core cooling and containment integrity for the specified duration. NAPS has developed a four hour coping analysis and installed an alternate AC system to address the requirements of 10 CFR 50.63.

NAPS is interconnected to the transmission system through switchyards operating at 500 kV and 230 kV. The 500 kV switchyard is of the “breaker and a half” design and has three 500 kV lines that connect to three independent substations within the VEPCO transmission system. The 230 kV switchyard has one 230 kV line that connects to an independent substation within the VEPCO transmission system. The 500 kV and 230 kV switchyards provide three offsite sources of power to the 34.5 kV switchyard that provides reserve station service power to the units. The 34.5 kV switchyard consists of buses 3, 4, and 5 with bus 3 supplied from 500 kV bus 1 through transformer 1, bus 4 supplied from 500 kV bus 2 through transformer 2, and bus 5 supplied from the 230 kV switchyard through transformer 3.

Three reserve station service transformers (RSSTs) supply offsite power to station transfer buses D, E, and F. RSST A and B receive power from either bus 4 or 5 and supply power to transfer buses D and E, respectively. RSST C receives power from either bus 3 or 5 and supplies power to transfer bus F. Transfer bus D powers emergency bus 1J (Unit 1), transfer bus E powers emergency bus 2H (Unit 2), and transfer bus F powers emergency buses 1H and 2J (Units 1 and 2, respectively). Electrical distribution system cables are routed from buses 3, 4 and 5 to the RSSTs via duct bank. Two backup circuits available for maintenance or outages on the underground circuits are routed overhead on distribution poles, but are not physically connected at each end. From the RSSTs, the electrical distribution system is routed to the turbine building via underground cables in duct bank and manholes and then via cable tray and conduit to the D, E, and F transfer buses in the normal switchgear room.

The boundary for the offsite SBO recovery path is the first circuit breaker and associated disconnect switches downstream of buses 3, 4, and 5. This boundary is consistent with the NRC standard review plan for subsequent license renewal, NUREG-2192, Section 2.5.2.1.1 boundary definition for the station blackout recovery path. The NUREG states that the in-scope plant system portion of the offsite power system includes equipment out to the first circuit breaker with the offsite distribution system. This path typically includes the circuit breakers that connect to the offsite system power transformers (reserve station service transformers for NAPS), the transformers, the intervening overhead and underground circuits between circuit breaker and transformer, and transformer and onsite electrical distribution system, and the associated control circuits and structures.

Structures and components that comprise the offsite SBO recovery path include:

- 34.5 kV circuit breakers (circuit breaker numbers 142, 152, 242, 252, 332, and 352) with associated control components (including cables), station post insulators, and disconnect switches (disconnect switch numbers 144, 145, 154, 155, 244, 245, 254, 255, 334, 335, 354, and 355) to connect the reserve station service transformer circuits to the transmission system
- 34.5 kV power conductors (insulated and uninsulated cable and connectors), insulators, and 3.5” aluminum tubular bus that connect from circuit breakers at switchyard buses 3, 4, and 5 to the RSSTs. This includes the two 34.5 kV overhead lines, and steel support poles, available as back-up in case of a failed underground line or as alternate feeders when the underground lines are out of service
- RSST A, B, and C, aluminum angle bus bars, ceramic insulators, insulated and uninsulated cables, duct bank and manholes, and connectors that connect to the line side of 4160V circuit breakers which power transfer buses D, E, and F
- Transfer buses D, E, and F, and the incoming 4160V breakers for each transfer bus (15D1, 15E1, and 15F1)
- Cables and 4160V circuit breakers connecting from transfer buses D, E, and F to emergency buses 1H, 1J, 2H, and 2J
- Emergency buses 1H, 1J, 2H, and 2J

- Aluminum tubular bus (5" and 6") and aluminum angle bus bars, ceramic insulators, insulated cables, duct bank and handholes, bus ducts, and connectors that connect the RSSTs to the 4160V circuit breakers which power the normal station service buses A, B, C and G of each unit. Also, 4160V bus duct that connects from the A RSST secondary bus bars to bus 1G, cubicle 15G11 and bus 2G, cubicle 25G8. (These components are not required for restoration of offsite power following an SBO event, but they cannot be isolated from the required power path and, therefore are included as additional scope for subsequent license renewal.)
- Manholes and ducts containing 34.5 kV insulated cables (Manhole sump pumps are included in the plumbing system)
- Power cables and connectors for sump pumps located in manholes associated with underground 34.5 kV cable
- Steel support structures and concrete foundations that support switchyard circuit breakers, disconnect switches, station post insulators, and power conductors
- Steel poles and concrete foundations, and precast concrete poles with carbon fiber reinforced polymer wraps that support 4160V tubular bus
- Switchyard control house and cable trench

The SBO coping and recovery paths are shown in Figure 2.1-1, SBO Recovery Path.

SBO coping is accomplished by the AAC generator supplying an emergency bus on each unit through transfer bus D, E, or F. The coping supply path from the AAC generator to transfer buses D and E is through breaker 05M1 to the 0M bus, through breakers 05M3 and 05L2 to the 0L bus, and then through breaker 05L3 to the D transfer bus or through breaker 05L1 to the E transfer bus. The D transfer bus then supplies the 1J emergency bus on Unit 1 through breakers 15D3 and 15J11. The E transfer bus then supplies the 2H emergency bus on Unit 2 through breakers 15E3 and 25H11. The coping supply path from the AAC generator to transfer bus F is through 05M1 to the 0M bus and then through breakers 05M2 and 15F5 to the F transfer bus. The F transfer bus then supplies either the 1H emergency bus on Unit 1 through breakers 15F3 and 15H11, or the 2J emergency bus on Unit 2 through breakers 15F4 and 25J11.

The SBO recovery path from offsite power is from either bus 3, 4, or 5 through RSST A, B, or C to transfer bus D, E, or F. Bus 3 supplies transfer bus F through switchyard breaker 332. Bus 4 supplies transfer bus D through switchyard breaker 142 and transfer bus E through switchyard breaker 242. Bus 5 can supply transfer bus D through switchyard breaker 152, transfer bus E through switchyard breaker 252, or transfer bus F through switchyard breaker 352. The transfer buses then power at least one emergency bus on each unit as follows: transfer bus D powers Unit 1 emergency bus 1J through breakers 15D3 and 15J11, transfer bus E powers Unit 2 emergency bus 2H through breakers 15E3 and 25H11, and transfer bus F powers Unit 1 emergency 1H through breakers 15F3 and 15H11 and/or Unit 2 emergency bus 2J through breakers 15F4 and 25J11.

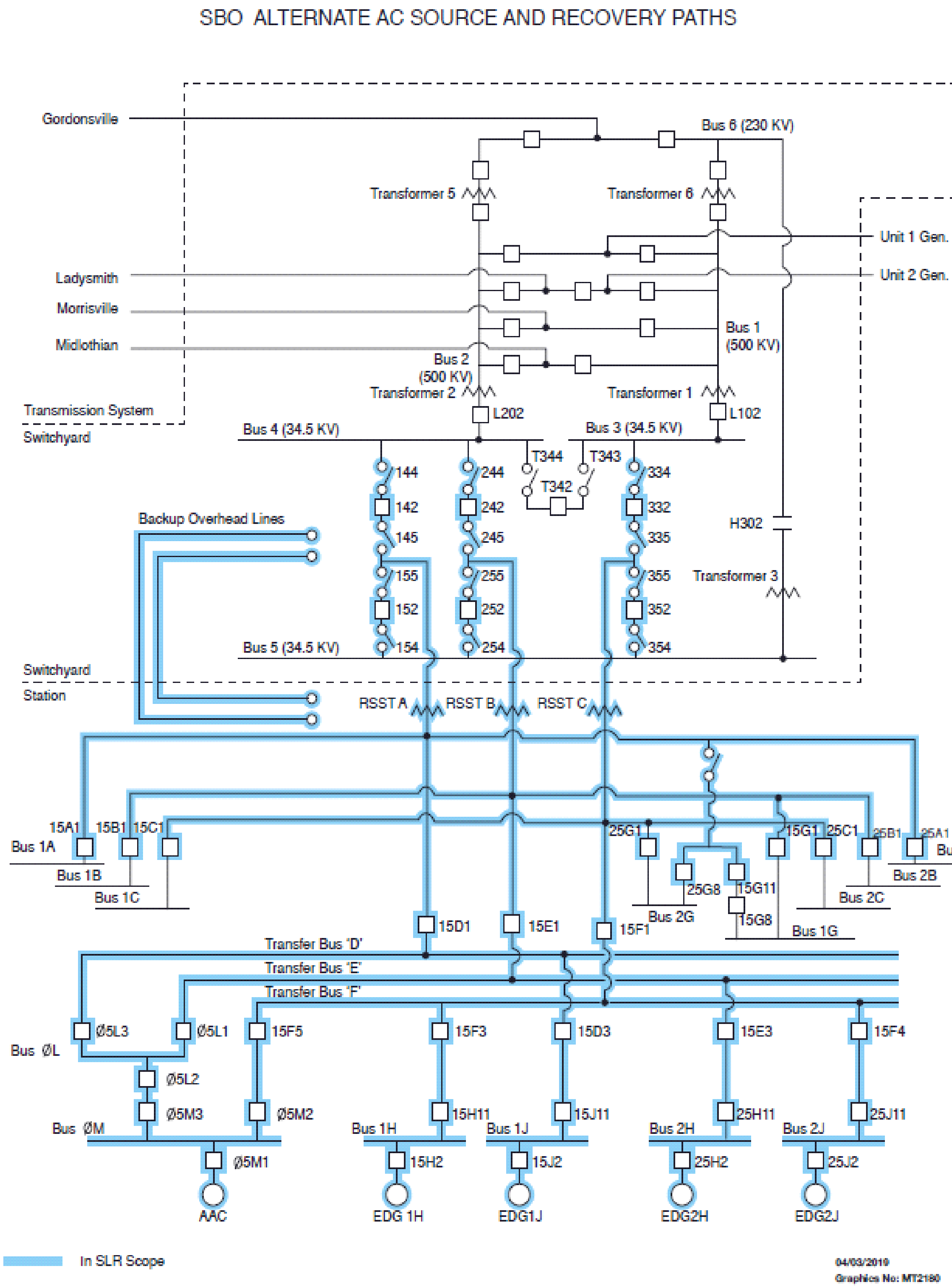
The SBO recovery path from onsite power is from the emergency diesel generators. EDG 1H powers Unit 1 emergency bus 1H through breaker 15H2, EDG 1J powers Unit 1 emergency bus 1J through breaker 15J2, EDG 2H powers Unit 2 emergency bus 2H through breaker 25H2, and EDG 2J powers Unit 2 emergency bus 2J through breaker 25J2.

Restoration of a 34.5 kV circuit through RSST A, B, or C or restoration of an emergency diesel generator meets the definition of recovery by re-powering the plant AC distribution system from offsite sources or onsite emergency AC sources and terminating the SBO event.

The SBO technical basis document summarizes the SBO coping and recovery requirements and includes a list of systems, structures, and components associated with SBO. SSCs classified as satisfying criterion 10 CFR 54.4(a)(3) related to SBO are included within the scope of subsequent license renewal.

Additional detail on the application of the 10 CFR 54.4(a)(3) scoping criteria is provided in Section 2.1.4.3.

Figure 2.1-1 SBO Recovery Path



2.1.4 SCOPING METHODOLOGY

The scoping process is the systematic process used to identify the NAPS systems, structures, and components within the scope of the license renewal rule. 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 intended functions were identified from a review of the CLB and design basis documents. In-scope boundaries were established and documented in the scoping evaluations, based on the identified intended functions. The in-scope boundaries form the basis for identification of the in-scope components, which is the first step in the screening process described in Section 2.1.5. System and structure scoping evaluations are documented and have been retained in a subsequent license renewal database. The system and structure scoping results are provided in Section 2.2.

The NAPS scoping process began with the development of a comprehensive list of plant systems and structures, as described in Section 2.1.3.1. The systems and structures were grouped into one of the following categories:

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

Each NAPS system and structure was scoped for subsequent license renewal using the criteria of 10 CFR 54.4(a). These criteria are briefly identified as follows:

- 10 CFR 54.4(a)(1) - Safety-related
- 10 CFR 54.4(a)(2) - Nonsafety-related affecting safety-related
- 10 CFR 54.4(a)(3) - Regulated Events:
  - 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)
  - Station Blackout (10 CFR 50.63)

The application of each of these criteria is discussed in Section 2.1.4.1, Section 2.1.4.2, and Section 2.1.4.3 below.

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

In accordance with 10 CFR 54.4(a)(1), the systems, structures and components within the scope of subsequent license renewal include:

> *Safety-related systems, structures, and components which are those relied upon to remain functional during and 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 shut down 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 §50.34(a)(1), §50.67(b)(2), or §100.11 of this chapter, as applicable.*

At NAPS, the safety-related plant components are identified in controlled engineering drawings and in the PAMS database. The safety-related classifications in the NAPS PAMS database were populated and maintained using a controlled procedure, with classification criteria consistent with the above 10 CFR 54.4(a)(1) criteria, as described in Section 2.1.3.2.

Safety-related classifications for systems and structures are based on PAMS safety classification, system and structure descriptions and analyses in the UFSAR, or on design basis documents such as engineering drawings, evaluations, or calculations. Systems and structures that are identified as safety-related in the UFSAR or in design basis documents have been classified as satisfying the criteria of 10 CFR 54.4(a)(1) and have been included within the scope of subsequent license renewal.

Plant conditions required per SLR-SRP, including conditions of normal operation, internal events, anticipated operational occurrences, design basis accidents, external events, and natural phenomena as described in the CLB, were considered for subsequent license renewal scoping.

The PAMS database includes some components that are conservatively classified as safety-related, but which are not relied upon for completion of a safety-related function. Components classified as safety-related in the PAMS database that do not support a safety-related system function were evaluated as nonsafety-related for subsequent license renewal scoping. Over classifications that affected scoping include the following;

The control room bottled air pressurization system, contains numerous components with safety classification SR in PAMS. These components do not perform any intended function per License Amendments 255/236.

Independent spent fuel storage installation casks are part of the fuel handling system and have a safety class of SR in PAMS. These casks are regulated under 10 CFR 72 and are, therefore, not within scope of subsequent license renewal.

The NAPS gaseous waste (GW) system contains components that are classified as safety-related (SR) for their function of retaining potentially radioactive gas. NUREG-1766, (the SER for the first license renewal application) Section 2.3.31.2 addresses scoping of GW components in the first LRA. Text includes: "The applicant clarified that those GW components, questioned by the staff, are classified as safety-related in the equipment data system (EDS). However, based on the results of the waste gas decay tank rupture accident analysis, the failure of these portions of the GW systems would result in dose consequences well below the guidelines of 10 CFR, Part 100. Therefore, these portions of the NAS and SPS GW systems have no intended functions [as defined in 10 CFR 54.4(a)(1)(iii)] and were determined to be not within the scope."

Because the waste gas decay tank rupture bounds the failure of other gaseous waste piping sections, it also bounds the failure of gaseous inputs to the gaseous waste system from connected systems. Several systems connect to the gaseous waste system through safety-related piping that serves only to retain potentially radioactive gas. These piping components were evaluated as nonsafety-related.

The component cooling system includes two valves and associated piping supports located in the Decontamination Building that are classified as safety-related. The pipes terminate at hose connections that are maintained isolated and are not used. Because the valves and piping downstream of the isolation valves remain isolated during operation, a failure of the valves or associated piping downstream of the isolation valves will not result in a loss of function of the component cooling system. The isolated component cooling piping, valves and support components (including piping within the Decontamination Building) do not perform a safety-related function, but are within scope for leakage boundary function (within the Fuel Building) or for structural integrity (within the Decontamination Building).

The inlet and outlet piping and valves to/from the boron recovery tanks, both in the pipe trench and in the boron recovery tank housing, are classified as safety-related, but do not support a safety-related function. Additionally, dike and waste disposal building sump outlet piping and valves are classified safety-related but do not perform a safety-related function. UFSAR, Section 3.8.1.1.8 describes the boron recovery tank dikes as seismic and tornado protected, such that the dikes serve to contain the entire volume of the tanks in the event of tank failure. A tank failure would result in no radiological consequences on the waters of the North Anna Reservoir, the Waste Heat Treatment Facility, or the potable water supply for the site. This event is not analyzed in UFSAR, Chapter 15 (accident analysis for offsite dose relative to 10 CFR 100), but is described in UFSAR, Chapter 11, in which event consequences are compared to 10 CFR 20. Therefore, the components are assigned safety-related quality for regulatory conformance, but do not perform a safety-related function, and are not within scope for SLR.

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 systems, structures and components within the scope of subsequent license renewal include:

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

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

- Functional support for safety-related SSC 10 CFR 54.4(a)(1) functions
- Connected to and provide structural support for safety-related SSCs
- Potential for spatial interactions with safety-related SSCs

Each of these categories is discussed below:

Functional Support for Safety-Related SSC 10 CFR 54.4(a)(1) Functions

This category addresses non-safety-related SSCs that are required to function in support of a safety-related SSC intended function. The functional requirement distinguishes this category from the other categories, where the nonsafety-related SSCs are required only to maintain adequate integrity to preclude structural failure or spatial interactions. The nonsafety-related SSCs that were included within the scope of subsequent license renewal to support a safety-related SSC in performing a 10 CFR 54.4(a)(1) intended function are identified on the subsequent license renewal boundary drawings in blue.

The NAPS UFSAR, CLB and other design basis documents were reviewed to identify nonsafety-related systems or structures required to support satisfactory accomplishment of a safety-related function. Nonsafety-related systems or structures credited in CLB documents to support a safety-related function have been included with the scope of subsequent license renewal. NAPS classifies systems that are required to perform or support a safety-related function as safety-related, with the following exceptions:

1. The turbine over-speed tripping devices, the stop valves, the throttle/governor valves, and the associated EHC system are relied on to prevent excessive turbine over-speed conditions that could lead to turbine rotor/disk failures, resulting in the generation of turbine missiles greater than those assumed in the UFSAR evaluations. However, the over-speed tripping devices, the valves, and the EHC system are not subject to aging management review (under 10 CFR 54.4(a)(1)) for the following reasons:

   a. The valve internals and over-speed tripping devices are specifically excluded from an aging management review as active components.

   b. The passive pressure boundary function of the valve bodies, the associated piping, and the EHC system is not needed to prevent turbine over-speed.

2. The drains - building services system chiller room sump pumps are safety-related. However, the pump discharge piping and valves are nonsafety-related, and are credited with mitigation of plant flooding, as described in UFSAR, Section 9.3.3.2.

3. The yard storm drains (evaluated within the drains - building services system) mitigate flooding, as described in UFSAR, Section 2.4.10.

4. The drains - aerated system removes water from the containment sub-surface drains to minimize hydrostatic pressure on the containment mat liner, as described in NUREG-1766 Confirmatory Action 3.8.1-2.

5. The fuel handling system reactor cavity water seal provides a pressure boundary to ensure water level in the cavity during fuel movement, as described in UFSAR, Section 9.1.4.3.1.

6. The refueling purification system provides a pressure boundary for reactor cavity integrity during refueling, as described in NUREG-1766, Section 2.3.3.4.1.

7. The neutron shield tank cooling system provides heat removal capability to cool the neutron shield tank and dissipate heat to the component cooling system, as described in UFSAR, Section 9.2.2.2.3.

8. Some nonsafety-related portions of systems are connected to safety-related (or (a)(2) functional) systems such that a portion of the nonsafety-related system must retain its integrity to support the integrity of the attached system. This function applies to the following systems:

   a. Bearing cooling

   b. Emergency diesel generator starting air

   c. Liquid waste

The nonsafety-related systems, or nonsafety-related portions of safety-related systems and structures that support the above functions, were included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(2).

A supporting system review was performed as an additional confirmation of scoping to meet 10 CFR 54.4(a)(2) criteria. The scoping process was performed on a system and structure basis. For systems included within the scope of subsequent license renewal in accordance with the requirements of 10 CFR 54.4(a)(1), the scoping evaluation included the identification of any additional systems, including nonsafety-related systems, that are required to support the safety-related system intended functions. It was then confirmed that these identified systems were also included in scope. Except as identified above, the NAPS systems required to support 10 CFR 54.4(a)(1) were classified safety-related, and as such were included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(1). The identification of support systems was not required for structures since structural intended functions do not rely on supporting systems.

The next two 10 CFR 54.4(a)(2) scoping categories are the subject of NEI 95-10, Appendix F (as referenced in NEI 17-01). The guidance requires that, when demonstrating failures of nonsafety-related systems would not adversely impact the ability to maintain intended functions, a distinction must be made between nonsafety-related systems that are directly connected to safety-related systems and those that are not directly connected to safety-related systems. For a nonsafety-related piping system that is directly connected to and provides structural support for a safety-related piping system; the nonsafety-related piping and supports shall be included within the scope of subsequent license renewal up to (1) the analytical boundary defined in the CLB seismic analysis for the safety-related piping or, (2) if the seismic boundary is not clearly defined in the CLB information, up to and including the point beyond which the failure of the nonsafety-related piping will not render the safety-related portion of the piping system unable to perform its intended function under CLB design conditions. The location of the point beyond which the failure of the nonsafety-related piping will not render the safety-related portion of the piping system unable to perform its intended function under CLB design conditions is identified using the guidance presented in NEI 95-10, Appendix F, Section 4 (as referenced in NEI 17-01).

The methodology for identification of NAPS SSCs that satisfy the 10 CFR 54.4(a)(2) scoping criterion was based on a review of applicable CLB and design basis documents, as well as plant specific and industry operating experience.

Connected to and Provide Structural Support for Safety-Related SSCs

The guidance of NEI 95-10, Appendix F (as referenced in NEI 17-01) was used to identify the endpoints of nonsafety-related piping components that are directly attached to, and provide support for, safety-related piping components. The attached nonsafety-related piping components must be included within scope up to and including the first seismic or equivalent anchor. NEI 95-10, Appendix F (as referenced in NEI 17-01) lists the following configurations that correspond to this requirement:

1. A seismic anchor is defined as a device or structure that ensures that forces and moments are restrained in three orthogonal directions.
2. An equivalent anchor may be defined in the CLB and can be credited for the 10 CFR 54.4(a)(2) evaluation.
3. An equivalent anchor may also consist of a large piece of plant equipment (e.g., a heat exchanger) 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.

4. There may be isolated cases where an equivalent anchor for a particular piping segment is not clearly described within the existing CLB information or original design basis. In those instances, a combination of restraints or supports such that the NSR piping and associated structures and components attached to the safety-related piping is included in scope up to a boundary point that encompasses at least two supports in each of three orthogonal directions.

An alternative to specifically identifying a seismic anchor or equivalent anchor is to include enough of the nonsafety-related piping run to ensure that these anchors are included and thereby ensure the piping and anchor intended functions are maintained. The following methods provide assurance that the included piping encompasses the nonsafety-related piping included in the design basis seismic analysis and is consistent with the current licensing basis:

a. A base-mounted component (e.g., pump, heat exchanger, tank, etc.) that is a rugged component and is designed not to impose loads on connecting piping. The subsequent license renewal scope should include the base-mounted component as it has a support function for the safety-related piping.

b. A flexible connection is considered a pipe stress analysis model end point when the flexible connection effectively decouples the piping systems (i.e., does not support loads or transfer loads across it to connecting piping).

c. A free end of nonsafety-related piping.

d. For nonsafety-related piping runs that are connected at both ends to safety-related piping include the entire run of nonsafety-related piping.

e. A point where the buried piping exits the ground. The buried portion of the piping should be included in the scope of subsequent license renewal.

f. A smaller branch line where the moment of inertia ratio of the larger piping to the smaller piping is equal to or greater than the acceptable ratio defined by the current licensing basis (ten, at NAPS), because significantly smaller piping does not impose loads on larger piping and does not support larger piping.

These scoping boundaries are determined from review of the physical installation details, design drawings, plant-specific piping analyses, or seismic analysis calculations.

Failure in nonsafety-related piping beyond the above anchor locations would not impact structural support for the safety-related piping. The associated piping and components included within the scope of subsequent license renewal are identified on the subsequent license renewal boundary drawings in orange. Symbols identifying the anchor locations and the CLB seismic analysis boundaries (or support boundaries) that define the structural support boundary for safety-related piping systems are shown on the subsequent license renewal boundary drawings. Note that if the connected nonsafety-related piping system contains water, steam, or oil, then the in-scope boundary may extend beyond the locations described above due to potential for spatial interaction with safety-related SSCs.

Potential for Spatial Interactions with Safety-Related SSCs

Nonsafety-related systems that are not connected to safety-related piping or components, or are outside the structural support boundary for the attached safety-related piping system, and have a spatial relationship such that their failure could adversely impact the performance of a safety-related SSC intended function, must be included within the scope of subsequent license renewal 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.

The mitigative option involves crediting plant mitigative features to protect safety-related SSCs from failures of nonsafety-related SSCs. Examples of plant mitigative features include pipe whip restrains, jet impingement shields, spray and drip shields, seismic supports, flood barriers, and physical barriers (e.g., floors, interior walls, doors, dampers). This option requires a demonstration that the mitigating features are adequate to protect safety-related SSCs from failures of nonsafety-related SSCs regardless of failure location. If this level of protection can be demonstrated, then only the mitigative features need be included within the scope of subsequent license renewal. Mitigative plant design features within structures are not used to exclude SSCs from the scope of subsequent license renewal at NAPS (except in the Decontamination Building) although mitigative features are included as within the scope of subsequent license renewal.

The Decontamination Building is not treated as a structure containing safety-related components. The Decontamination Building houses safety-related solenoid valves in the heating and ventilation system that are protected from spatial interactions by the electrical panel in which they're housed. If the solenoids or their air supply should fail (or deenergize), the safety-related ventilation alignment is established. The panel completely encloses the solenoids to shield them from spatial interactions that might result in the solenoids establishing an undesired, energized configuration. These solenoid valves credit only the mitigative feature for spatial effects. The electrical panel is addressed as a civil / structural commodity. The Decontamination Building does not house other components that are relied upon to support a safety-related function.

The preventive option involves identifying the nonsafety-related SSCs that have a spatial relationship such that failure could adversely impact the performance of a safety-related SSC intended function, and including the identified nonsafety-related SSC within the scope of subsequent license renewal without consideration of plant mitigative features.

NAPS applied the preventive option for 10 CFR 54.4(a)(2) scoping. The preventative option as implemented at NAPS is based upon a “spaces” approach for determining potential for spatial interactions with safety-related SSCs. The boundaries for the “spaces” are structure boundaries that act as physical barriers and separate safety-related targets from nonsafety-related hazards.

Nonsafety-related piping and components that contain water, oil, or steam are not excluded from scope unless it can be demonstrated that they are not in proximity to safety-related SSCs. This is demonstrated by confirming that there are no safety-related SSCs located within the same space (e.g., structure or enclosure) as the nonsafety-related piping or component containing water, oil, or steam (with the exception of the Decontamination Building, in which only a mitigative feature is credited, as described above). This demonstration is based on confirming that there are adequate physical barriers (e.g., structural boundaries) separating the nonsafety-related piping or component from safety-related SSCs, thereby preventing the potential spatial interaction. The structural barrier components are included in scope. No credit is taken for separation by distance alone without a physical barrier capable of preventing the spatial interaction.

Potential spatial interaction is assumed for nonsafety-related SSCs that contain water, oil, or steam and that are located within structures that contain safety-related SSCs that are relied upon to perform safety-related functions. The structures of concern for potential spatial interaction were identified based on a review of the CLB to determine which structures contained active or passive safety-related SSCs. It is assumed that nonsafety-related SSCs within structures containing safety-related SSCs may be located in proximity to safety-related SSCs.

Nonsafety-related piping and components that contain water, oil, or steam, and are located inside structures that contain safety-related SSCs, are included within the scope of subsequent license renewal for potential spatial interaction in accordance with the requirements of criterion 10 CFR 54.4(a)(2), as recommended by NEI 95-10, Appendix F. High-energy lines located within structures that contain safety-related equipment are included within the scope of subsequent license renewal, in accordance with 10 CFR 54.4(a)(1) or (a)(2), depending on their safety classification. Safety-related high energy lines are in scope in accordance with 10 CFR 54.4(a)(1), and nonsafety-related high-energy lines are in scope in accordance with 10 CFR 54.4(a)(2). Potential spatial interaction due to leakage or spray is assumed for system pressure as low as atmospheric. Supports for nonsafety-related SSCs within these structures are included in scope.

Air and gas systems (non-liquid) are not a hazard to other plant equipment, and do not have potential for spatial interactions with safety-related SSCs. SSCs containing air or gas cannot adversely affect safety-related SSCs due to leakage or spray, since gas systems contain no liquids that could spray or leak onto safety-related systems to cause shorts or other malfunctions. NAPS operating experience was reviewed and confirmed that there have been no failures due to aging in systems containing air or gas that have adversely impacted the accomplishment of a safety-related function. Additionally, air and gas systems at NAPS are classified as moderate energy systems. As described in NEI 95-10, Appendix F, paragraph 5.2.2.2.2, physical impact from pipe whip or jet impingement from moderate energy systems do not occur and need not be considered. Thus, the nonsafety-related systems containing air or gas are not included within the scope of subsequent license renewal for spatial interaction. The supports are included in scope to prevent the nonsafety-related piping from falling and potentially impacting safety-related SSCs.

The piping systems included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(2) for potential spatial interaction with safety-related SSCs are identified on the subsequent license renewal boundary drawings in orange.

Scoping of Abandoned Mechanical Components

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

1. The abandoned piping components do not provide structural or seismic support to attached safety-related piping, and
2. The abandoned piping is separated from sources of water by blanks, blind flanges or pipe caps. Closed valves are not credited to keep fluid from abandoned components, and
3. The abandoned piping is empty of fluid. Piping was verified to be empty by establishing configuration (such as the piping being open-ended at the low point), by review of documents that abandoned the equipment, or by ultrasonic testing or other method that is capable of confirming the absence of trapped fluid.

If the above conditions are not met, the abandoned systems or portions thereof are included within the scope of LR for aging management. Abandoned equipment is not relied on to perform any function delineated in 10 CFR 54.4(a)(1) or (a)(3) as it is non-operational.

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

In accordance with 10 CFR 54.4(a)(3), the systems, structures, and components within the scope of subsequent 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).*

For each of the five regulations, a technical basis document was prepared to provide input into the scoping process. Each of the regulated event technical basis documents (described in Section 2.1.3.4) identify the systems and structures that are relied upon to demonstrate compliance with the applicable regulation. The technical basis documents also identify the source documentation used to determine the scope of components within the system that are credited to demonstrate compliance with each of the applicable regulated events. Guidance provided by the technical basis documents was incorporated into the system and structure scoping evaluations, to determine the SSCs credited for each of the 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 subsequent license renewal.

2.1.4.4 System and Structure Intended Functions

For the systems and structures within the scope of subsequent license renewal, the intended functions that are the bases for including them within the scope of subsequent license renewal are identified and documented in the scoping evaluation. The system or structure intended functions are based on the applicable CLB reference documents. For systems, the system level intended function descriptions associated with 10 CFR 54.4(a)(1) are consistent with the categories of nuclear safety criteria for pressurized water reactors as documented in industry standard ANSI/ANS-51.1-1983, “Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants” (Reference 1.7-14), to provide for consistent function application and appropriate level of detail for system level intended function descriptions. The component level intended functions are the passive component functions that are necessary to support the system or structure intended function(s). The structure and component intended functions are further described in Section 2.1.5.2.

2.1.4.5 Scoping Boundary Determination

Systems and structures that are included within the scope of subsequent license renewal are then further evaluated to determine the population 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 processes for evaluating mechanical systems, electrical systems and structures are each different, primarily because the plant design document formats are different. Mechanical systems are depicted primarily on the system piping and instrumentation diagrams (P&ID) that show the system components and their functional relationships, while structures are depicted on layout drawings. Electrical and I&C components of in-scope electrical and in-scope mechanical systems are placed into commodity groups and are screened as commodities. Scoping boundaries for mechanical systems, structures, and electrical and I&C systems are, therefore, described separately.

Mechanical Systems

For mechanical systems, the mechanical components that support the system intended functions are included within the scope of subsequent license renewal and are depicted on the applicable system piping and instrumentation diagram. Mechanical system piping and instrumentation diagrams are marked up to create subsequent license renewal boundary drawings showing the in-scope, passive components. Components that are not long-lived are identified on the drawings with notes. Components that are required to support a safety-related function, or a function that demonstrated compliance with one of the subsequent license renewal regulated events are identified on the system piping and instrumentation diagrams by blue highlighting. Nonsafety-related components that are connected to safety-related components and are required to provide structural support at the safety/nonsafety interface, or components whose failure could prevent satisfactory accomplishment of a safety-related function due to spatial interaction with safety-related SSCs, are identified by orange highlighting. Drawings identify the system with which they are primarily associated. In-scope, passive components from a different system, whose primary depiction is on another drawing, are highlighted in gray. A download of associated system components from the PAMS database confirms the scope of components in the system. Plant walkdowns were performed when required for additional confirmation.

Structures

For structures, the structural components that are required to support the intended function(s) of the structure are included within the scope of subsequent license renewal. The structural components are identified from a review of applicable plant design drawings of the structure, applicable UFSAR sections, and design basis documentation. Reviews of mechanical and electrical subsequent license renewal scoping documents were performed to ensure that structures and structural components required to support in-scope mechanical and electrical SSCs were included in the structural scope. Plant walkdowns were performed when required for additional confirmation. Structural bolting required to support the structure proper is evaluated with the structure. Structural bolting associated with a component support or a structural commodity component is evaluated with the component support or structural commodity components. Site plant layout drawings are marked up to create subsequent license renewal boundary drawings which highlight structures within the scope of subsequent license renewal.

Electrical

A list of electrical and instrumentation and control (I&C) systems was developed and the systems were scoped against the criteria of 10 CFR 54.4(a). The list of electrical and I&C systems and the results of the scoping are provided in Table 2.2-1.

<ins>System Level Scoping</ins>

At the system level, the scoping methodology utilized for electrical and I&C systems was similar to the mechanical system-level scoping. Electrical and I&C systems were identified from the PAMS equipment database by system designation code. The PAMS equipment database does not list electrical component types such as high-voltage transmission conductors, high voltage insulators, and switchyard bus and connections. These components, associated with the offsite SBO recovery path, were grouped into the switchyard SBO recover path system, created for this purpose, and included in the scoping process. The UFSAR descriptions, CLB documents and design basis documents applicable to each system were reviewed to determine the system safety classification and to identify the system functions. System level functions were evaluated against the criteria of 10 CFR 54.4(a)(1), (a)(2), and (a)(3). The results of the system level scoping along with a list of references supporting the evaluation of each electrical and instrumentation and control system were documented.

Component Level Scoping

Components of electrical and I&C systems that were determined to be within scope of subsequent license renewal, and electrical and I&C components within mechanical systems that were determined to be within scope of subsequent license renewal, did not require evaluation to determine which components were required to perform or support the identified intended functions. A bounding scoping approach was used for electrical and I&C components. Electrical and I&C components within in-scope systems were included within the scope of subsequent license renewal with the exception that some fuse holders were evaluated to confirm that they did not support a system intended function. In-scope electrical and I&C components were placed into commodity groups and were evaluated as commodities during the screening process as described in Section 2.1.5.1.

Structural components which support or interface with electrical components, such as structural supports, cable trays, conduits, instrument racks, panels and enclosures, are evaluated as structural components in Section 2.4.1.38.

Unlike mechanical systems, individual subsequent license renewal boundary drawings were not created for each electrical and I&C system.

2.1.5 SCREENING PROCEDURE

Once the SSCs within the scope of subsequent license renewal have been determined, the next step is to determine which structures and components are subject to an aging management review.

2.1.5.1 Identification of Structures and Components Subject to AMR

The requirement to identify structures and components subject to an aging management review is specified in 10 CFR 54.21(a)(1), which states:

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

1. For those system, 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.

Structures and components that perform an intended function without moving parts or without a change in configuration or properties are defined as passive for subsequent license renewal. Passive structures and components that are not subject to replacement based on a qualified life or specified time period are defined as long-lived for subsequent license renewal. The screening procedure is the process used to identify the passive, long-lived structures and components within the scope of subsequent license renewal. These structures and components are subject to aging management review.

NUREG-2192 and NEI 95-10, Appendix B, were used as the basis for the identification of passive structures and components, as recommended by NEI 17-01, Section 1.1. Most passive structures and components are long-lived. Boundary drawing notes identify the cases where a passive component is determined not to be long-lived.

The NAPS structures and components subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.21(a)(1) described above. The process implemented to meet these requirements for mechanical systems, structures, and electrical commodities is described as follows:

Mechanical Systems

The mechanical system screening process began with the results from the scoping process. For in-scope mechanical systems, the written descriptions and marked up system piping and instrumentation diagrams clearly identify the in-scope system boundary of passive components for subsequent license renewal. The marked up system piping and instrumentation diagrams are called subsequent license renewal boundary drawings. These system boundary drawings were reviewed to identify the passive, long-lived components, and the identified components were entered into the subsequent license renewal database. Component listings from the PAMS database were also reviewed to confirm that system components were considered during the process. In cases where the system piping and instrumentation diagram did not provide sufficient detail, such as for some large vendor supplied components (e.g., chillers, emergency diesel generators), the associated component drawings or vendor manuals were also reviewed. Plant walkdowns were performed when required for confirmation. Short-lived components were excluded from aging management review. The bases for their exclusion were documented and notes were added to the system boundary drawings to identify their status.

A complex assembly is a predominantly active assembly where the performance of its components is closely linked to that of the intended function of the entire assembly, such that testing and monitoring of the assembly is sufficient to identify degradation of these components. Examples of complex assemblies include diesel generators and chiller units. Complex assemblies are considered active and can be excluded from the requirements of AMR. 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 aging management review. This follows the screening methodology for complex assemblies as described in Table 2.1-2 of NUREG-2192.

Note that safety-related air operated valves normally fail to their safety position. For these components, the supply of compressed air does not support the system intended function. Safety-related components such as solenoid valves whose only function is to vent the air from these valve operators are within scope, but the function is performed by active internal components, and the passive pressure boundary of the valve body or piping components does not contribute to the safety-related function. Therefore, these components are not subject to aging management review.

Mechanical components are screened with the system in which they were scoped. For heat exchangers, the entire heat exchanger is evaluated within the system in which it is identified in PAMS.

Structures

Structures and structural components typically perform their functions without moving parts and without a change in configuration or properties. When a structure or structural component was determined to be within the scope of subsequent license renewal by the scoping process described in Section 2.1.4.5, the structure screening methodology classified the component as active or passive. Active components do not require aging management. This is consistent with guidance found in NEI 95-10, Appendix B, as referenced by NEI 17-01. During the structure screening process, the intended function(s) of passive structural components were documented. In the structure screening process, an evaluation was made to determine whether in-scope structural components were subject to replacement based on a qualified life or specified time period. If an in-scope structural component was determined to be subject to replacement based on a qualified life or specified time period, the component was identified as short-lived and was excluded from an AMR. In such a case, the basis for determining that the structural component was short-lived was documented.

Electrical Commodities

Screening of electrical and I&C components within the in-scope electrical, I&C, and mechanical systems used a bounding approach as described in NEI 17-01 (Reference 1.7-6). Electrical and I&C components for the in-scope systems were assigned to commodity groups based on the listing in NUREG-2192, Table 2.1-6. Commodities subject to an aging management review were identified by applying 10 CFR 54.21(a)(1) to identify those commodities that perform their function without moving parts or a change in configuration ("passive" components). This method provides the most efficient means for determining the electrical commodities subject to an aging management review since many electrical and I&C components are active. Passive commodity groups were reviewed, and any that did not perform an intended function were determined to not require an aging management review. The remaining passive commodity groups were screened consistent with 10 CFR 54.21(a)(1)(ii) to exclude those commodities that are subject to replacement based on a qualified life or specific time period from the requirements of an aging management review. The remaining passive commodities were determined to be subject to aging management review. The electrical commodities that require an aging management review are identified in Section 2.5.

2.1.5.2 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 subsequent license renewal. A component intended function is defined as a passive component function that must be performed in order for the system or structure to be able to perform the system or structure intended function(s). For example, pressure boundary failure of a component would cause loss of inventory from the system, and the system would subsequently be unable to perform its intended function(s). Structures and components may have multiple intended functions. NAPS 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 in this application.

Table 2.1-1 Passive Structure and Component Intended Function Definitions

Intended Function Abbreviation	Intended Function
BWI	Water barrier: Provides barrier to contain water inventory.
CE	Conducts electricity: Provides electrical connections to specified sections of an electrical circuit to deliver voltage, current, or signals.
EN	Enclosure protection: Provides enclosure, shelter and/or protection for in-scope equipment (including radiation shielding and pipe whip restraint).
FB	Fire barrier: Provides rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant.
FD	Flow distribution: Provides for flow distribution to or from a desired component or area.
FLB	Flood barrier: Provides a protective barrier for internal/external flood events.
FLT	Filtration: Provides filtration.
HT	Heat transfer: Provides for heat transfer.
IN	Insulate: Provides electrical insulation
JIS	Jet impingement shield: Provides jet impingement shielding for high-energy line breaks
LB	Leakage boundary (spatial): Nonsafety-related component that maintains mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs. This function includes providing structural support to safety-related components, where applicable.
LTC	Limit thermal cycling: Limits thermal cycling (thermal sleeves).
MB	Missile barrier: Provides a missile (internal/external) barrier.
MCI	Coating integrity: Maintains coating integrity to prevent clogging of the emergency core cooling systems.
PB	Pressure boundary: Provides pressure boundary for delivery of sufficient flow at adequate pressure, or control room pressure boundary integrity, or containment integrity.
RF	Restricts flow: Provides flow restriction.
SCW	Source of cooling: Provides a source of cooling water for plant shutdown.
SI	Structural integrity (attached): Nonsafety-related component that maintains mechanical and structural integrity to provide structural support to attached safety-related piping and components.
SP	Spray pattern: Provides a spray pattern.
SS	Structural support: Provides structural and/or functional support to safety-related and/or nonsafety-related components.
TI	Thermal insulation: Provides thermal insulation.

2.1.5.3 Stored Equipment

Stored equipment that has a PAMS database component entry is evaluated with the applicable system. Some equipment not in the PAMS database is staged for use by the Fire Brigade, such as smoke ejectors and ventilation trunks, but is not relied upon for fire protection or safe shutdown.Other fire-fighting equipment, such as extinguishers, air packs and fire hoses are addressed as consumables.

There are a small number of components stored in a warehouse, or in the Technical Support Center that are staged for use to achieve safe shutdown following a fire. This equipment consists of cabling and cable lugs of various gauges, flexible ventilation ducting, air or nitrogen bottles and regulators, and air hoses (for manual operation of air-operated valves). These components are within the scope of subsequent license renewal and are subject to aging management review. The cabling and cable lugs are evaluated with the electrical equipment, the ventilation ducting is evaluated with the ventilation system, and the air bottles, valves, and hoses are evaluated with the instrument air system.

2.1.5.4 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 (4) groups for the purpose of subsequent license renewal: (a) packing, gaskets, component seals, and O-rings; (b) structural sealants; (c) oil, grease, and components filters; and (d) system filters, fire extinguishers, fire hoses, and air packs.

- Group (a) subcomponents (packing, gaskets, component seals, and O-rings): Managing loss of leak tightness due to degraded packing, gaskets, component seals, and O-rings for the pressure boundary and leakage boundary intended functions is not required. It is unlikely that leakage from packing, gaskets, component seals, and O-rings would result in failure of the system to deliver sufficient flow at adequate pressure. In regard to leakage, NAPS routinely conducts tours of the operating spaces. When leakage is detected it is entered into the corrective action program. The leakage is corrected by replacing the packing, gaskets, component seals, and O-rings as consumables. Therefore, these subcomponents are not subject to aging management review.
- Group (b) structural sealants: Aging management reviews were required for structural sealants in structures within the scope of subsequent license renewal. A summary of the AMR Results is presented in Section 3.5.

- Group (c) subcomponents (oil, grease, and component filters): These subcomponents are short-lived and are periodically replaced. Various plant procedures are used in the replacement of oil, grease, and filters in components that are in scope for subsequent license renewal. Therefore, these subcomponents are not subject to an aging management review.
- Group (d) consumables (system filters, fire extinguishers, fire hoses, and air packs): System filters are replaced in accordance with plant procedures based on vendor manufacturers' requirements and system testing. Fire extinguishers, self-contained breathing air packs, and fire hoses are within the scope of subsequent license renewal but are not subject to aging management because they are replaced based on condition. These components are periodically inspected in accordance with Branch Technical Position APSCB 9.5-1, NFPA 10A for portable fire extinguishers, 29 CFR 1910.134 for self-contained breathing air packs, and NFPA 1962 for fire hoses. These standards require replacement of equipment based on their condition or performance during testing and inspection. These components are subject to replacements implemented by controlled procedures and are therefore not long-lived and not subject to aging management review.

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). The following draft SLR-ISGs have been issued for use and comment but have not been incorporated in NUREG-2191 or NUREG-2192 at the time of submittal:

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

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

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

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

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

  The AMPs are revised to allow 5-year inspections of manholes with water level monitoring and alarms. In addition, there is no need for event-driven inspections if there is no water accumulation in the manholes. The Electrical Insulation for Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program (B2.1.39), Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program (B2.1.40), and Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program (B2.1.41) incorporate the guidance presented in this SLR-ISG.

- XI.E7, High Voltage Insulators

  The AMP is revised to add polymer and toughened glass high-voltage insulators to the scope and program elements and include all insulators operating at or above medium voltage. The High Voltage Insulators program (B2.1.45) incorporates the guidance presented in this SLR-ISG.

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

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

- XI.S8, Protective Coating Monitoring and Maintenance

  The AMP revises the frequency of inservice coating inspection monitoring to no later than 6 years based on trending of the total amount of permitted degraded coatings. The Protective Coating Monitoring and Maintenance program (B2.1.36) incorporates the guidance presented in this SLR-ISG.

- NUREG-2192 Section 3.5 (Fatigue Waiver)

  An option is provided to perform a further evaluation based on ASME Code, Section III, Division 1, Subsection NE, fatigue waiver analysis for containment metallic pressure-retaining boundary components that are subject to cyclic loading but have no current licensing basis (CLB) fatigue analysis. If the ASME Code fatigue waiver acceptance criteria are met then cracking due to cyclic loading does not require aging management. Further evaluation and AMR lines are provided in Section 3.5, Aging Management of Containment, Structures and Components Supports.

- NUREG-2192 Section 3.5 (Plant-Specific Aging Management Options)

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

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

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

- X.M2, Neutron Fluence Monitoring

  The AMP is revised to reference approaches that have been found to be acceptable in recent staff reviews of extended beltline and reactor vessel internals fluence calculations, as RG 1.190 is not applicable. The Neutron Fluence Monitoring program (B3.2) incorporates the guidance presented in this SLR-ISG.

- XI.M2, Water Chemistry

  The AMP and UFSAR Supplement are revised to include the latest revision of EPRI guidelines for BWRs and PWRs. The Water Chemistry program (B2.1.2) and UFSAR Supplement (A1.2) incorporate the guidance presented in this SLR-ISG.

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

  The AMP was revised to add the 2019 Edition of ASME Code, Section XI, Non-mandatory Appendix C, which provides flaw evaluation procedures for CASS with ferrite content ≥ 20 percent. The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel program (B2.1.6) incorporates the guidance presented in this SLR-ISG

- XI.M21A, Closed Treated Water System

  The AMP was revised to include the latest revision of EPRI closed cooling water chemistry guidelines. The Closed Treated Water System program (B2.1.12) incorporates the guidance presented in this SLR-ISG.

- XI.M26, Fire Protection

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

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

  The SLR-ISG revises NUREG-2191, Table VII.H2 “Emergency Diesel Generator System” and makes conforming changes to NUREG-2192, Table 3.3-1 to include line items to manage the reduction of heat transfer for a steel heat exchanger radiator exposed internally to diesel fuel oil and include a line item for managing loss of material for nickel alloy externally exposed to diesel fuel oil. AMR lines have been provided in Section 3.3, Aging Management of Auxiliary Systems.

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

  The AMP was revised to recommend opportunistic inspections, in lieu of periodic inspections, as an acceptable alternative for buried internally coated/lined fire water system piping if certain conditions are met. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (B2.1.28) incorporates the guidance presented in this SLR-ISG.

2.1.7 GENERIC SAFETY ISSUES

In accordance with the guidance in NEI 17-01 and Appendix A.3 of NUREG-2192, review of NRC generic safety issues (GSIs) as part of the subsequent license renewal process is required to satisfy 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 aging management review or time-limited aging analysis evaluation are to be addressed in the LRA. A review of the version of NUREG-0933 current six months prior to the subsequent license renewal application submittal, including the applicable Generic Issue Management Control System Report, determined that there were no outstanding USIs, or high- or medium-priority GSIs. The GSIs noted below were reviewed to assure they did not involve aging effects for structures and components subject to an aging management review or time-limited aging analysis evaluation:

- GSI-186, Potential Risk and Consequences of Heavy Load Drops in Nuclear Power Plants — This GSI addresses heavy load issues related to crane design and operation. Aging effects are not central to these issues. The issue does not involve time limited aging analysis evaluations. This issue is now closed (Reference ML113050589).
- GSI-189, Susceptibility of Ice Condenser Containments to Early Failure from Hydrogen Combustion during a Severe Accident — This GSI is not applicable to NAPS, which does not have ice condenser containments. This issue is now closed (Reference ML13190A244).
- GSI-191, Assessment of Debris Accumulation on PWR Sump Performance — This GSI 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 (sump screens) are evaluated with the recirculation spray system as described in Section 2.3.2.2. The protective coatings inside containment are evaluated with the Containment Structure as described in Section 2.4.1.1 The issue is not related to the 60-year term of the current operating license; and, therefore, it is not a TLAA.
- GSI-193, BWR ECCS Suction Concerns — This GSI addresses the possible failure of low pressure emergency core cooling systems due to unanticipated, large quantities of entrained gas in the suction piping from the pressure suppression chamber (torus) in BWR Mark I containments. This issue is not applicable to NAPS, which is a PWR. This issue is closed (Reference ML16082A288).
- GSI-199, Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States — This GSI 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.
- GSI-204, Flooding of Nuclear Power Plant Sites Following Upstream Dam Failures — This GSI 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.

NUREG-0933 was reviewed and there are no new generic issues that involve issues related to subsequent license renewal aging management reviews or TLAAs.

2.1.8 CONCLUSION

The scoping and screening methodology described above was used at NAPS to identify the systems and structures that are within the scope of subsequent license renewal and to identify those structures and components that are subject to an aging management review. The 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 lists the NAPS systems, structures and commodity groups that were evaluated to determine if they were within the scope of license renewal, using the methodology described in Section 2.1. A reference to the section of the application that contains the scoping and screening results is provided for each in-scope mechanical system, structure and commodity group in the Table. For electrical systems, a relevant UFSAR reference is provided, if one exists.

Table 2.2-1 Plant-Level Scoping Results

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference
Reactor Vessel, Internals, and Reactor Coolant System			
Reactor Vessel	N/A	Yes	2.3.1.1
Reactor Vessel Internals	N/A	Yes	2.3.1.2
Reactor Coolant	RC	Yes	2.3.1.3
Steam Generator	N/A	Yes	2.3.1.4
Engineered Safety Features			
Quench Spray	QS	Yes	2.3.2.1
Recirculation Spray	RS	Yes	2.3.2.2
Residual Heat Removal	RH	Yes	2.3.2.3
Safety Injection	SI	Yes	2.3.2.4
Auxiliary Systems			
Fuel Pit Cooling	FC	Yes	2.3.3.1
Refueling Purification	RP	Yes	2.3.3.2
Primary Grade Water	PG	Yes	2.3.3.3
Helium Vacuum Drying	HVD	Yes	2.3.3.4
Fuel Handling	FH	Yes	2.3.3.5
Materials Handling	MH	Yes	2.3.3.6
Service Water	SW	Yes	2.3.3.7
Bearing Cooling	BC	Yes	2.3.3.8
Circulating Water	CW	Yes	2.3.3.9
Vacuum Priming	VP	Yes	2.3.3.10
Domestic Water	DW	Yes	2.3.3.11
Component Cooling	CC	Yes	2.3.3.12

Table 2.2-1 Plant-Level Scoping Results

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference
Neutron Shield Tank Cooling	NS	Yes	2.3.3.13
Instrument Air	IA	Yes	2.3.3.14
Service Air	SA	Yes	2.3.3.15
Primary and Secondary Plant Gas Supplies	GN	Yes	2.3.3.16
Penetration Electrical	PE	Yes	2.3.3.17
Leakage Monitoring	LM	Yes	2.3.3.18
Chemical and Volume Control	CH	Yes	2.3.3.19
Boron Recovery	BR	Yes	2.3.3.20
Sampling	SS	Yes	2.3.3.21
Incore Instrumentation	IC	Yes	2.3.3.22
Decontamination	DC	Yes	2.3.3.23
Drains - Aerated	DA	Yes	2.3.3.24
Drains - Building Services	BLD, DB	Yes	2.3.3.25
Drains - Gaseous	DG	Yes	2.3.3.26
Gaseous Waste Disposal	GW	Yes	2.3.3.27
Liquid and Solid Waste	LW	Yes	2.3.3.28
Oil Separation	OS	Yes	2.3.3.29
Radioactive Waste	RW	Yes	2.3.3.30
Sanitary Sewage	PB	Yes	2.3.3.31
Vents - Gaseous	VG	Yes	2.3.3.32
Containment Vacuum	CV	Yes	2.3.3.33
Chilled Water	CD	Yes	2.3.3.34
Heating and Ventilation	HV	Yes	2.3.3.35

Table 2.2-1 Plant-Level Scoping Results

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference
High Radiation Sampling	HRS	Yes	2.3.3.36
Post-Accident Hydrogen Removal	HC	Yes	2.3.3.37
Radiation Monitoring	RM	Yes	2.3.3.38
Alternate AC	AAC, BCW, BFO, BLO, BSA	Yes	2.3.3.39
Emergency Diesel Generator	EE, EB, EC, EG, EL, FO	Yes	2.3.3.40
Security	SEC	Yes	2.3.3.41
Fire Protection	FP	Yes	2.3.3.42
Containment Access	CE	Yes	2.3.3.43
Generator Breaker Cooling	GB, PH	Yes	2.3.3.44
Water Treatment	WT	Yes	2.3.3.45
Steam and Power Conversion Systems			
Main Steam	MS, GS	Yes	2.3.4.1
Auxiliary Boilers	AB	Yes	2.3.4.2
Extraction Steam	ES	Yes	2.3.4.3
Auxiliary Steam	AS	Yes	2.3.4.4
Feedwater	FW	Yes	2.3.4.5
Condensate	CN	Yes	2.3.4.6
Condensate Polishing	CP	Yes	2.3.4.7
Steam Drains	SD, SV	Yes	2.3.4.8

Table 2.2-1 Plant-Level Scoping Results

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference
Blowdown	BD	Yes	2.3.4.9
Lubricating Oil	LO, TM	Yes	2.3.4.10
Main Generator Seal Oil	GM	Yes	2.3.4.11
Electro-Hydraulic Control	EH	Yes	2.3.4.12
Beyond Design Basis	BDB	No	N/A
Bearing Lube	BL	No	UFSAR 10.4.2
Compressed Air (Control Room Breathing Air)	CA	No	UFSAR 9.4.1
Laboratory Vacuum	LV	No	N/A
Spillway (or Main Dam)	SP	No	UFSAR 3.8.3
Vacuum Priming Seal Water	VSW	No	N/A
Containments, Structures, and Component Supports			
Containment		Yes	2.4.1.1
Administration Building		Yes	2.4.1.2
Auxiliary Building		Yes	2.4.1.3
Auxiliary Feedwater Pump House		Yes	2.4.1.4
Auxiliary Feedwater Tunnel		Yes	2.4.1.5
Boron Recovery Building		Yes	2.4.1.6
Casing Cooling Pump House		Yes	2.4.1.7
Circulating Water Intake Tunnel Header		Yes	2.4.1.8
Containment Mat Subsurface Pump Access Shaft		Yes	2.4.1.9
Decontamination Building		Yes	2.4.1.10
Dikes, Firewalls, and Equipment Foundations		Yes	2.4.1.11
Discharge Tunnel and Seal Pit		Yes	2.4.1.12
Domestic Water Treatment Building		Yes	2.4.1.13

Table 2.2-1 Plant-Level Scoping Results

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference
Duct Banks		Yes	2.4.1.14
Flood Protection Dike		Yes	2.4.1.15
Fuel Building		Yes	2.4.1.16
Fuel Oil Pump House		Yes	2.4.1.17
Intake Structure		Yes	2.4.1.18
Main Steam Valve House		Yes	2.4.1.19
Maintenance Building		Yes	2.4.1.20
Manholes		Yes	2.4.1.21
New Fuel Receiving Building		Yes	2.4.1.22
Quench Spray Pump House		Yes	2.4.1.23
Safeguards Building		Yes	2.4.1.24
SBO Building		Yes	2.4.1.25
SBO Structures for Offsite Power		Yes	2.4.1.26
Security Diesel Building		Yes	2.4.1.27
Security Lighting Poles		Yes	2.4.1.28
Service Building		Yes	2.4.1.29
Service Water Pump House		Yes	2.4.1.30
Service Water Reservoir		Yes	2.4.1.31
Service Water Valve House		Yes	2.4.1.32
Tank Foundations and Missile Barriers		Yes	2.4.1.33
Turbine Building		Yes	2.4.1.34
Vaults, Enclosures, and Pits		Yes	2.4.1.35
Waste Disposal Building		Yes	2.4.1.36
Waste Solidification Building		Yes	2.4.1.37

Table 2.2-1 Plant-Level Scoping Results

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference
Component Supports		Yes	2.4.1.38
Miscellaneous Structural Commodities		Yes	2.4.1.39
NSSS Supports		Yes	2.4.1.40
Spent Fuel Cask Handling Structure		No	N/A
Waste Heat Treatment Facility		No	N/A
Main Dam		No	N/A
Service Water Reservoir Horizontal Drains and Piezometers		No	N/A
Service Water Chemical Addition Building		No	N/A
Bearing Cooling Tower		No	N/A
Clean Waste Segregation Building		No	N/A
Compressed Gas Storage Shelter		No	N/A
Condensate Storage Tank Foundation		No	N/A
Emergency Response Vehicle Building		No	N/A
Fire Pump House Embankment		No	N/A
Independent Spent Fuel Storage Facility (ISFSI)		No	N/A
Information Center (NANIC)		No	N/A
Meteorological Tower and Station		No	N/A
Old Steam Generator Storage Facility		No	N/A
Old Visitors Center		No	N/A
PBX (Communications) Building		No	N/A
Primary Grade Water Tank Foundation		No	N/A
Radio Tower and Building		No	N/A
Records Storage Building		No	N/A
Sewage Treatment Facility		No	N/A

Table 2.2-1 Plant-Level Scoping Results

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference
Training Building		No	N/A
Vacuum Priming Pump House		No	N/A
Warehouse #5 Fire Pump House		No	N/A
Security Buildings		No	N/A
Transmission Line Towers		No	N/A
Warehouses, Various Shops and Office Buildings Outside the Protected Area		No	N/A
BDB Building		No	N/A
Electrical and I&C Systems			
Ambient Air Monitoring	AM	Yes	UFSAR 3C.5.4.6.2
Batteries, 125V DC System & Components	BY	Yes	UFSAR 8.3.2
Computer	CM	Yes	UFSAR 7.7.1.10
Communications	CO	Yes	UFSAR 9.5.2
Electrical Instrumentation	EI	Yes	UFSAR 7
Emergency Lighting	ELT	Yes	UFSAR 9.5.3
Electrical Power	EP	Yes	UFSAR 8.3
Emergency Response Capability	ERC	Yes	UFSAR 7.7.1.10 and 7.8
Fire Protection Monitoring	FPM	Yes	UFSAR 9.5.1.2.3
Pressurizer Heaters	HS	Yes	UFSAR 5.1.1.5 and 7.7.1.5
Heat Tracing	HT	Yes	UFSAR 9.3.4.2.4, 9.5.1.2.1 and 11.4.3.1
Nuclear Instrumentation	NI	Yes	UFSAR 7.2 and 7.7
Neutron Monitoring	NM	Yes	UFSAR 7.5
Rod Control System	RCS	Yes	UFSAR 4.2.3

Table 2.2-1 Plant-Level Scoping Results

System, Structure, or Commodity Group	PAMS ID	In Scope for License Renewal	Reference
Reactor Protection System	RPS	Yes	UFSAR 7.2
Solid State Protection System	SSP	Yes	UFSAR 7.3
Switchyard SBO Recovery Path (SWYD)	N/A	Yes	N/A
Vital Bus	VB	Yes	UFSAR 8.3.1.2
Valve Monitoring System	VMS	Yes	UFSAR 7.6.7
Control Rod Drive Power Supply	ED	No	UFSAR 7.2.1
Earthquake Reporting	ER	No	UFSAR 3.7.4
Early Warning	EW	No	N/A
Generic EQML Components	GEC	No	N/A
Large Motor Monitoring	LMM	No	N/A
Loose Parts Monitoring	LPM	No	UFSAR 5.2.5.3
Meteorological Monitoring	MM	No	UFSAR 2.3.3.2
Rod Position Indication	RPI	No	N/A

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2.3 SCOPING AND SCREENING RESULTS: MECHANICAL SYSTEMS

2.3.1 REACTOR VESSEL, INTERNALS, AND REACTOR COOLANT SYSTEM

2.3.1.1 Reactor Vessel

System Description

The Unit 1 and 2 reactor vessels are categorized as standard Westinghouse 157-inch internal diameter three-loop reactor vessels. Each reactor vessel is a cylindrical shell with a welded, hemispherical lower head and a flanged hemispherical upper head. The reactor vessel provides structural support for the reactor core and a pressure boundary for the reactor coolant in which the core is submerged.

The reactor vessel shell is constructed of forged rings (upper, intermediate, and lower) welded together circumferentially.

The reactor vessel is vertically mounted on welded support pads attached to the bottom of the primary nozzles, which are spaced circumferentially around the reactor vessel just below the reactor vessel flange. The hot-leg and cold-leg reactor coolant loop piping for each of the three loops is welded to the primary nozzles. The internal surfaces of the reactor vessel in contact with borated reactor coolant are clad with a stainless steel overlay, which provides corrosion resistance. The lower head has penetrations (instrumentation tubes), for movable in-core nuclear flux thimble tubes, which extend into the reactor vessel interior and mate with the lower internals assembly. The core support ledge, located inside the reactor vessel just below the vessel flange, supports the weight of the reactor vessel internals and the fuel. The lower internals assembly hangs from the core support ledge and is provided with lateral support by core support lugs.

The reactor vessel flange and the closure head flange are joined by 58 six-inch closure studs, nuts, and spherical washers. Two concentric, hollow, metallic O-rings between the closure head flange and the reactor vessel flange form an inner and outer seal. A dynamic seal is formed when the closure head is bolted in place and by the internal pressure in the reactor vessel.

The reactor vessel closure head dome is penetrated by the control rod drive mechanism housing tubes and a vent pipe.

Nozzle support pads located below the primary nozzles provide an interface for support of the reactor vessel. The weight of the reactor vessel is transmitted through the nozzle support pads to the neutron shield tank that surrounds the reactor vessel.

System Evaluation Boundary

The evaluation boundary for the reactor vessel components subject to aging management review includes the reactor vessel shell and flange, welded attachments, nozzles, safe ends and flanges, control rod drive mechanism housings and head adapter plugs, instrumentation tubes, the reactor vessel closure head, closure stud assemblies, lifting lugs, and seal table components. The neutron shield tank is evaluated with the reactor coolant system, and its structural support function is further described in Section 2.4.1.40, NSSS Supports. The closure head flange O-rings are periodically replaced every refueling outage, and are therefore, not subject to aging management review.

System Intended Functions

The reactor vessel performs the following safety-related functions: The reactor vessel maintains the reactor coolant system pressure boundary and provides fission product boundaries; supports and contains the reactor core and core support structures; supports and contains the control rod drive mechanism internals; supports and guides reactor controls and instrumentation; and contains the reactor coolant around the reactor core and directs the coolant flow into the core and out into the reactor coolant piping and upper head. Therefore, the reactor vessel is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The reactor vessel is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Pressurized Thermal Shock (10 CFR 50.61), and Station Blackout (10 CFR 50.63). Therefore, the reactor vessel is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the reactor vessel can be found in the UFSAR, Sections 5.4 and 15.4, and Table 5.2-22.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the reactor vessel are listed below:

13075-SLRM-093C Sh. 1

13075-SLRM-093D Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.1-1 Reactor Vessel.

The aging management review results for these component types are indicated in Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation.

2.3.1.2 Reactor Vessel Internals

System Description

The reactor vessel internals are designed to direct coolant flow, support the reactor core, and guide the control rod assemblies when in the withdrawn position.

The reactor vessel internals consist of two basic assemblies: an upper internals assembly that is removed during each refueling operation to obtain access to the reactor core, and a lower internals assembly, which includes the core barrel and baffle/former assembly that can be removed, if desired, following a complete core unload.

The lower internals assembly is supported in the reactor vessel by clamping to a ledge below the vessel-head mating surface and closely guided at the bottom by radial support/clevis assemblies. The core support ledge supports the entire weight of the reactor vessel internals and the fuel. The lower internals assembly hangs from the ledge. A circumferential spring rests on top of the lower internal flange, which rests on the ledge.

The upper internals assembly rests on the spring. The spring is compressed when the vessel head is lowered and tightened down, holding the lower internals assembly against the core support ledge and the upper internals assembly against the vessel head. This minimizes flow-induced vibrations and prevents upward motion of the lower internals assembly. The bottom of the upper internals assembly is closely guided by the core plate alignment pins.

System Evaluation Boundary

The evaluation boundary for the reactor vessel internals system components that are subject to aging management review includes the subcomponents of the control rod guide tube assemblies, upper internals assembly, baffle-former assembly, bottom-mounted instrumentation, core barrel assembly, lower internals assembly, lower support assembly, thermal shield assembly, and alignment and interfacing components. Fuel assemblies are periodically replaced, and control rods are active components; therefore, these components are not subject to aging management review.

System Intended Functions

The reactor vessel internals perform the following safety-related functions: The reactor vessel internals support and orient the fuel assemblies and control rod assemblies, direct the coolant flow to and from the core components, and support and guide the incore instrumentation. Also, the reactor vessel internals provide a secondary support structure for limiting the core support structure downward displacement, and provide gamma and neutron shielding for the reactor vessel. Therefore, the reactor vessel internals are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

UFSAR References

Additional details of the reactor vessel internals can be found in the UFSAR, Section 4.2.2 and Figures 4.2-16, 4.2-17, 4.2-18, and 4.2-19.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the reactor vessel internals.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.1-2 Reactor Vessel Internals.

The aging management review results for these component types are indicated in Table 3.1.2-2 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel Internals - Aging Management Evaluation.

2.3.1.3 Reactor Coolant

System Description

The reactor coolant system transfers heat produced in the reactor core to the steam generators, where steam is generated to drive the turbine generator. Reactor coolant is circulated through the core at a flow rate and temperature consistent with achieving the desired reactor core thermal-hydraulic performance. The reactor coolant also acts as a neutron moderator, a reflector, and a solvent for the neutron absorber.

The reactor coolant system provides a pressure boundary for containing the reactor coolant. It also serves to confine radioactive material and limits uncontrolled release to the secondary system and the other parts of the plant.

The reactor coolant system consists of three piping loops (A, B, and C) interconnected at the reactor vessel. Each loop consists of one reactor coolant pump, one steam generator, valves, and interconnecting piping. The pressurizer, connected to Loop C hot leg, provides a means for controlling reactor coolant system pressure. The reactor coolant system also contains piping and components that allow venting of the reactor vessel and pressurizer.

During operation, the reactor coolant system heat capacity attenuates thermal transients. Reactor coolant system piping is used by the safety injection system to deliver cooling water to the core for emergency cooling and shutdown during a loss-of-coolant accident (LOCA).

The reactor coolant system also includes the reactor coolant pump motor oil collection system components.

The reactor coolant system includes a neutron shield tank located inside the biological shield wall around the reactor vessel. The neutron shield tank provides support for the reactor vessel and limits heat transferred to the biological shield wall concrete. The neutron shield tank is described further in the structural commodities (NSSS supports) section. Cooling for the neutron shield tank is described in the neutron shield tank cooling system.

System Evaluation Boundary

The evaluation boundary for the reactor coolant system components subject to aging management review includes the piping and components from the reactor vessel nozzle safe-ends to the steam generator inlet nozzle safe-ends, and from the steam generator outlet nozzle safe-ends through the reactor coolant pumps to the reactor vessel inlet nozzle safe-ends. The evaluation boundary includes the pressurizer surge line, pressurizer spray lines, and pressurizer and pressurizer subcomponents. The pressurizer spray head does not form part of the reactor coolant pressure boundary and is not credited for mitigation of any of the accidents addressed in UFSAR Chapter 15. The spray head does not provide structural support to reactor coolant pressure boundary components and does not have a (nonsafety-related) leakage boundary function, as it is not designed to retain water without leakage, and is entirely contained within the pressurizer. The internal and external surfaces of the spray head are exposed to nearly the same pressure, and the potential for generation of loose parts due to cracking is a hypothetical system interaction that has not been reported in industry operating experience. The spray head is not credited for compliance with regulated events. Therefore, the pressurizer spray head is not within the scope of subsequent license renewal.

The evaluation boundary includes nonsafety-related components that provide support to directly-connected safety-related components, or that retain water, steam or oil in buildings containing safety-related components.

The reactor vessel, reactor vessel internals, and steam generators are within the scope of subsequent license renewal, but are evaluated separately in other subsequent license renewal application sections.

The evaluation boundary also includes a neutron shield tank, which is located inside the biological shield wall around the reactor vessel, and the reactor coolant pump motor oil collection system components.

System Intended Functions

The reactor coolant system performs the following safety-related functions: The reactor coolant system provides a pressure boundary for the reactor coolant; removes core decay, latent, and reactor coolant pump heat; and controls core reactivity during normal operations, shutdown and following a design basis event. The system also mitigates the consequences of design basis events, provides non-EQ safety-related instrumentation, and provides containment isolation. Therefore, the reactor coolant system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The reactor coolant system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the reactor coolant system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The reactor coolant system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), and Station Blackout (10 CFR 50.63). Therefore, the reactor coolant system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the reactor coolant system can be found in the UFSAR, Section 3.1, and Chapters 5 and 15.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the reactor coolant system are listed below:

11715-SLRM-079B Sh. 5

11715-SLRM-093A Sh. 1

11715-SLRM-093A Sh. 2

11715-SLRM-093A Sh. 3

11715-SLRM-093B Sh. 1

11715-SLRM-093B Sh. 2

11715-SLRM-093B Sh. 3

11715-SLRM-093E Sh. 1

12050-SLRM-079A Sh. 5

12050-SLRM-093A Sh. 1

12050-SLRM-093A Sh. 2

12050-SLRM-093A Sh. 3

12050-SLRM-093B Sh. 1

12050-SLRM-093B Sh. 2

12050-SLRM-093B Sh. 3

12050-SLRM-093E Sh. 1

13075-SLRM-093C Sh. 1

13075-SLRM-093C Sh. 2

13075-SLRM-093D Sh. 1

13075-SLRM-093D Sh. 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.1-3 Reactor Coolant.

The aging management review results for these component types are indicated in Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation.

2.3.1.4 Steam Generator

System Description

Three steam generators are installed in each unit with one steam generator installed in each of the three reactor coolant loops. The steam generators are vertical, shell and U-tube heat exchangers with integral moisture-separating equipment. The steam generators function to transfer heat from the single-phase, high-pressure, high-temperature borated reactor coolant on the primary side of the tubes to the two-phase steam-water mixture on the secondary side of the tubes. The internal surfaces of the steam generator in contact with borated reactor coolant, with the exception of the nickel alloy channel head divider plate, are clad with a stainless steel or nickel alloy weld overlay, which provides corrosion resistance.

The steam generator is a recirculating design and consists of a primary (tube) side and a secondary (shell) side. Reactor coolant flows through the primary side through inverted U-tubes, entering and leaving through the primary nozzles located in the hemispherical bottom chamber (channel head). The channel head is welded to a plate (tubesheet) from which the tube bundle extends. The channel head is divided into inlet and outlet chambers by a vertical divider plate extending from the channel head to the tubesheet. Manways are provided for access to both sides of the divided channel head. Pressure boundary integrity is maintained by manway covers that are bolted to the manways.

On the secondary side, tube support plates, stay rods, stay rod spacer pipes, and anti-vibration bars are provided for structural support of the U-tubes.

The steam generator tube bundle is contained inside a cylindrical wrapper. The space between the wrapper and the inside of the steam generator shell forms an annular region called the downcomer. Feedwater enters the steam generator through the feedwater inlet nozzle located in the upper shell and is distributed around the periphery of the steam generator by an internal feedwater distribution ring (feedring). The feedwater exits the top of the feedring through J-nozzles, where it mixes with recirculated water from the moisture separators and flows down the downcomer. The mixture of subcooled feedwater and saturated recirculated water exits the downcomer at the tube sheet, where it flows under the wrapper and is distributed across the tube sheet. The mixture is heated to boiling by reactor coolant heat transferred through the U-tubes. The saturated steam/water mixture enters the moisture separator section, where liquid is removed from the mixture and returned to the evaporator section. Essentially dry steam exiting the moisture separator section is conducted through the steam outlet nozzle that is fitted with a flow-limiting device designed to limit steam flow in the event of a main steam pipe rupture.

Secondary side penetrations (handholes, access ports, blowdown nozzles, instrument taps, and manways) are provided for instrumentation, maintenance, and inspection activities.

A nozzle in the upper shell facilitates the maintenance of wet layup chemistry conditions in the steam generator during shutdown periods via the steam generator recirculation and transfer system.

System Evaluation Boundary

The evaluation boundary for the steam generator components subject to aging management review includes the subcomponents that provide pressure integrity, structural support, flow distribution, and steam flow restriction.

System Intended Functions

The steam generators perform the following safety-related functions: The steam generators remove core decay, latent and reactor coolant pump heat during normal operations, shutdown, and following a design basis event; provide a pressure boundary for the reactor coolant during normal operations, shutdown, and following a design basis event; and limit the steam release rate during a main steam line break transient. Therefore, the steam generators are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The steam generators are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, the steam generators are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the steam generator can be found in the UFSAR, Sections 5.2.1, 5.5.2, 10.3.2, and 15.4.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the steam generator are listed below:

11715-SLRM-093A Sh. 1

11715-SLRM-093A Sh. 2

11715-SLRM-093A Sh. 3

12050-SLRM-093A Sh. 1

12050-SLRM-093A Sh. 2

12050-SLRM-093A Sh. 3

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.1-4 Steam Generator.

The aging management review results for these component types are indicated in Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator - Aging Management Evaluation.

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Screening Results Tables: Reactor Vessel, Internals, and Reactor Coolant System

Table 2.3.1-1 Reactor Vessel

Subcomponent	Intended Function(s)
Bottom head dome	Pressure Boundary
Bottom mounted instrumentation guide tube	Pressure Boundary
Bottom mounted instrumentation nozzle and weld	Pressure Boundary
Closure head dome	Pressure Boundary
Closure head flange	Pressure Boundary
Closure head lifting lug	Structural Support
Closure head stud, nut, and washer	Pressure Boundary
Control rod drive mechanism (head adapter plug)	Pressure Boundary
Control rod drive mechanism (housing (head adapter) flange)	Pressure Boundary
Control rod drive mechanism (housing (head adapter) tube)	Pressure Boundary
Control rod drive mechanism (latch housing)	Pressure Boundary
Control rod drive mechanism (nozzle, head vent nozzle, j-groove weld)	Pressure Boundary
Control rod drive mechanism (rod travel housing)	Pressure Boundary
Core support lug, pad and weld	Structural Support
Instrumentation port assembly	Pressure Boundary
Instrumentation tube	Pressure Boundary
Instrumentation tube safe end	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.1-1 Reactor Vessel

Subcomponent	Intended Function(s)
Primary nozzle and support pad	Pressure Boundary, Structural Support
Primary nozzle safe end	Pressure Boundary
Refueling seal ledge	Structural Support
Seal table	Structural Support
Seal table fitting	Pressure Boundary
Vent pipe nozzle	Pressure Boundary
Ventilation shroud support ring	Structural Support
Vessel flange and core support ledge	Pressure Boundary, Structural Support
Vessel flange leakage monitor tube	Pressure Boundary
Vessel shell (upper, intermediate, and lower)	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.1.2-1, Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.1-2 Reactor Vessel Internals

Subcomponent	Intended Function(s)
Alignment and interfacing (clevis bearing wear surface)	Structural Support
Alignment and interfacing (clevis insert bolt and dowel)	Structural Support
Alignment and interfacing (internals hold down spring)	Structural Support
Alignment and interfacing (thermal sleeve)	Structural Support
Alignment and interfacing (upper core plate alignment pin)	Structural Support
Baffle former (baffle edge bolt)	Structural Support
Baffle former (baffle former bolt)	Structural Support
Baffle former (baffle plate)	Flow Distribution, Structural Support
Baffle former (former plate)	Structural Support
Bottom mounted instrumentation (column body)	Structural Support
Bottom-mounted instrumentation (flux thimble tube)	Structural Support
Control rod guide tube (continuous section sheath and C-tube)	Structural Support
Control rod guide tube (guide plate - Unit 2 only)	Structural Support
Control rod guide tube (guide plate)	Structural Support
Control rod guide tube (lower flange - Unit 2 only)	Structural Support
Control rod guide tube (lower flange)	Structural Support

See Table 2.1-1 for definitions of intended functions.

Table 2.3.1-2 Reactor Vessel Internals

Subcomponent	Intended Function(s)
Core barrel (barrel former bolt)	Structural Support
Core barrel (core barrel flange)	Flow Distribution, Structural Support
Core barrel (lower axial weld)	Structural Support
Core barrel (lower flange weld)	Structural Support
Core barrel (lower girth weld)	Structural Support
Core barrel (middle axial weld)	Structural Support
Core barrel (upper axial weld)	Structural Support
Core barrel (upper flange weld)	Structural Support
Core barrel (upper girth weld)	Structural Support
Lower internals (fuel alignment pin)	Structural Support
Lower internals (lower core plate)	Flow Distribution, Structural Support
Lower internals (radial support key wear surface)	Structural Support
Lower support (column body)	Structural Support
Lower support (column bolt)	Structural Support
Lower support (lower support forging)	Structural Support
No additional measures components	Flow Distribution, Spray Pattern, Structural Support
Thermal shield (flexure)	Structural Support
Upper internals (fuel alignment pin)	Structural Support
Upper internals (upper core plate)	Structural Support

See Table 2.1-1 for definitions of intended functions.

Table 2.3.1-2 Reactor Vessel Internals

Subcomponent	Intended Function(s)
Upper internals (upper support ring)	Structural Support

The aging management review results for these component types are indicated in Table 3.1.2-2, Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel Internals - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.1-3 Reactor Coolant

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Drip pan (reactor coolant pump oil collection)	Pressure Boundary
Enclosure (reactor coolant pump oil collection)	Pressure Boundary
Flame arrestor	Pressure Boundary
Flexible hose	Pressure Boundary
Heat exchanger (reactor coolant pump motor lower bearing oil - tube)	Pressure Boundary
Heat exchanger (reactor coolant pump motor stator - fin)	Heat Transfer
Heat exchanger (reactor coolant pump motor stator - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (reactor coolant pump motor upper bearing oil - channel head)	Pressure Boundary
Heat exchanger (reactor coolant pump motor upper bearing oil - shell)	Pressure Boundary
Heat exchanger (reactor coolant pump motor upper bearing oil - tube)	Pressure Boundary
Heat exchanger (reactor coolant pump motor upper bearing oil - tubesheet)	Pressure Boundary
Heat exchanger (thermal barrier)	Heat Transfer, Pressure Boundary
Hydraulic isolator	Pressure Boundary
Insulation (RTD)	Thermal insulation
Orifice	Pressure Boundary, Restricts Flow

See Table 2.1-1 for definitions of intended functions.

Table 2.3.1-3 Reactor Coolant

Component Type	Intended Function(s)
Piping (reactor vessel flange leakage detection line)	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Piping, piping components (Class 1)	Pressure Boundary
Piping, piping components (Class 1<NPS 4)	Pressure Boundary
Pressurizer (heater well and sheath)	Pressure Boundary
Pressurizer (instrument nozzle)	Pressure Boundary
Pressurizer (lower head)	Pressure Boundary
Pressurizer (manway cover bolting)	Pressure Boundary
Pressurizer (manway cover)	Pressure Boundary
Pressurizer (manway)	Pressure Boundary
Pressurizer (relief nozzle safe end)	Pressure Boundary
Pressurizer (relief nozzle)	Pressure Boundary
Pressurizer (relief, safety, spray, and surge nozzle welds)	Pressure Boundary
Pressurizer (safety nozzle safe end)	Pressure Boundary
Pressurizer (safety nozzle)	Pressure Boundary
Pressurizer (sample nozzle)	Pressure Boundary
Pressurizer (shell)	Pressure Boundary
Pressurizer (seismic support lug)	Structural Support
Pressurizer (spray nozzle safe end)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.1-3 Reactor Coolant

Component Type	Intended Function(s)
Pressurizer (spray nozzle thermal sleeve)	Limit Thermal Cycling
Pressurizer (spray nozzle)	Pressure Boundary
Pressurizer (support skirt and flange)	Structural Support
Pressurizer (surge nozzle safe end)	Pressure Boundary
Pressurizer (surge nozzle thermal sleeve)	Limit Thermal Cycling
Pressurizer (surge nozzle)	Pressure Boundary
Pressurizer (upper head)	Pressure Boundary
Pump casing (reactor coolant)	Pressure Boundary
Rupture disc	Pressure Boundary
Sight glass	Pressure Boundary
Sight glass (body)	Pressure Boundary
Tank (calibration test pots)	Leakage Boundary (Spatial)
Tank (neutron shield)	Pressure Boundary, Structural Support
Tank (pressurizer relief)	Pressure Boundary
Tank (reactor coolant pump oil collection)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary
Valve body (Class 1)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

The aging management review results for these component types are indicated in Table 3.1.2-3, Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.1-4 Steam Generator

Subcomponent	Intended Function(s)
Anti-vibration bar	Structural Support
Channel head	Pressure Boundary
Channel head divider plate	Flow Distribution
Feedwater distribution ring and J-nozzles	Flow Distribution
Feedwater nozzle	Pressure Boundary
Feedwater nozzle thermal sleeve	Limit Thermal Cycling
Moisture separator assembly	Flow Distribution
Primary inlet and outlet nozzle	Pressure Boundary
Primary inlet and outlet nozzle safe end	Pressure Boundary
Primary inlet and outlet nozzle weld	Pressure Boundary
Primary manway	Pressure Boundary
Primary manway cover	Pressure Boundary
Primary manway cover bolting	Pressure Boundary
Primary manway cover insert	Pressure Boundary
Secondary closure cover	Pressure Boundary
Secondary closure cover bolting	Pressure Boundary
Secondary manway (includes pad)	Pressure Boundary
Secondary side shell (lower shell, upper shell, transition cone, closure weld, girth weld)	Pressure Boundary
Secondary side shell (penetrations)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.1-4 Steam Generator

Subcomponent	Intended Function(s)
Secondary side shell (upper head)	Pressure Boundary
Stay rod and spacer	Structural Support
Steam flow limiter	Restricts Flow
Steam outlet nozzle	Pressure Boundary
Support pad	Structural Support
Tube	Heat Transfer, Pressure Boundary
Tube bundle wrapper	Flow Distribution, Structural Support
Tube plug	Pressure Boundary
Tube support plate	Flow Distribution, Structural Support
Tubesheet	Pressure Boundary
Tube-to-tubesheet weld	Structural Support

The aging management review results for these component types are indicated in Table 3.1.2-4, Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

2.3.2 ENGINEERED SAFETY FEATURES

2.3.2.1 Quench Spray

System Description

The quench spray system is designed to pump cool, borated water from the refueling water storage tank, mixed with a sodium hydroxide solution from the chemical addition tank, through spray ring headers and nozzles into the Containment. The spray solution absorbs heat from the containment atmosphere to reduce pressure and prevent challenging the structural integrity of the Containment. In addition, the spray reduces the airborne iodine concentration in the post-LOCA containment atmosphere to maintain accident dose within limits.

The refueling water storage tank also provides the source of water to the safety injection system for the injection phase of design basis accident mitigation. The UFSAR describes the quench spray system as a subsystem of the containment depressurization system.

System Evaluation Boundary

The evaluation boundary for the quench spray system components subject to aging management review includes the refueling water storage tank and chemical addition tank, the attached piping through the quench spray pumps to the spray headers and associated branch piping, and nonsafety-related piping and components that provide a leakage boundary or structural integrity function. The foundations for the refueling water storage tank and chemical addition tank are addressed in the structural section of this application.

System Intended Functions

The quench spray system performs the following safety-related functions: The system is relied upon to cool and depressurize the Containment and remove radioactive iodine from the containment atmosphere following a design basis event. The system delivers cool borated water to the containment sump to ensure adequate net positive suction head for outside recirculation spray pump operation. The system also performs a containment isolation function, and includes safety-related instrumentation. Therefore, the quench spray system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The quench spray system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the quench spray system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The quench spray system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49) and Station Blackout (10 CFR 50.63).

Therefore, the quench spray system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the quench spray system can be found in the UFSAR, Section 6.2.2 and Table 6.2-37.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the quench spray system are listed below:

11715-SLRM-091A Sh. 1

11715-SLRM-091A Sh. 2

12050-SLRM-091A Sh. 1

12050-SLRM-091A Sh. 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.2-1, Quench Spray.

The aging management review results for these component types are indicated in Table 3.2.2-1, Engineering Safety Features - Quench Spray - Aging Management Evaluation.

2.3.2.2 Recirculation Spray

System Description

The recirculation spray system is designed to provide long-term heat removal from the containment atmosphere and core cooling water following a design basis loss of coolant accident (LOCA). The recirculation spray system transfers heat from the reactor core, via coolant spilled from the break, and from the containment atmosphere to the service water system through the recirculation spray heat exchangers. Water collected in the containment sump is pumped through the heat exchangers, then through spray ring headers and nozzles, into the containment atmosphere. The recirculation spray system is designed to return the post-LOCA Containment to subatmospheric pressure and to maintain subatmospheric conditions for the duration of the accident recovery, thus preventing outleakage of fission products. The cooled water in the containment sump is pumped back through the reactor core by the safety injection system.

Casing cooling components of the recirculation spray system provide a source of cool, borated water to the suction of the outside containment recirculation spray pumps to provide adequate net positive suction head. The UFSAR describes the recirculation spray system as a subsystem of the containment depressurization system.

System Evaluation Boundary

The evaluation boundary for the recirculation spray system components subject to aging management review includes the casing cooling tanks, pumps and flowpath to the outside recirculation spray pump suction; the containment sump strainer (screens); the flowpath through the recirculation spray pumps through the heat exchangers to the spray rings, and the attached branch piping and nonsafety-related components that perform a leakage boundary or structural integrity function.

System Intended Functions

The recirculation spray system performs the following safety-related functions: The system, in conjunction with the quench spray system, depressurizes the Containment and removes radioactive iodine following a design basis accident; provides containment isolation; provides long term core cooling following a design basis accident; and provides non-EQ safety-related instrumentation. Therefore, the recirculation spray system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The recirculation spray system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the recirculation spray system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The recirculation spray system is relied upon for compliance with regulations for Environmental Qualification (10 CFR 50.49). Therefore, the recirculation spray system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the recirculation spray system can be found in the UFSAR, Section 6.2.2 and Table 6.2-37.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the recirculation spray system are listed below:

11715-SLRM-091A Sh. 3

11715-SLRM-091A Sh. 4

11715-SLRM-091B Sh. 1

12050-SLRM-091A Sh. 3

12050-SLRM-091A Sh. 4

12050-SLRM-091B Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.2-2, Recirculation Spray.

The aging management review results for these component types are indicated in Table 3.2.2-2, Engineering Safety Features - Recirculation Spray - Aging Management Evaluation.

2.3.2.3 Residual Heat Removal

System Description

The residual heat removal system transfers heat from the reactor coolant system to the component cooling system during reactor shutdown conditions. Water is drawn from the reactor coolant system, pumped through the residual heat removal heat exchangers, and returned to the reactor coolant system to control primary system temperature. The residual heat removal system is in service only when reactor coolant system temperature and pressure have been reduced to 350°F and 450 psig, respectively.

System Evaluation Boundary

The evaluation boundary for the residual heat removal system components subject to aging management review includes the flowpath from the reactor coolant system, through the residual heat removal pumps and heat exchangers and back to the reactor coolant system via the safety injection accumulator discharge lines, the branch lines to other systems, and nonsafety-related components with a leakage boundary or structural integrity function.

System Intended Functions

The residual heat removal system performs the following safety-related functions: The system removes heat from the reactor coolant system; mixes reactor coolant to ensure uniform boron concentration; provides a safety-related pressure boundary; provides containment isolation; and provides non-EQ safety-related instrumentation. Therefore, the residual heat removal system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The residual heat removal system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the residual heat removal system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The residual heat removal system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the residual heat removal system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the residual heat removal system can be found in the UFSAR, Section 5.5.4 and Table 6.2-37.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the residual heat removal system are listed below:

11715-SLRM-094A Sh. 1

11715-SLRM-094A Sh. 2

12050-SLRM-094A Sh. 1

12050-SLRM-094A Sh. 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.2-3, Residual Heat Removal.

The aging management review results for these component types are indicated in Table 3.2.2-3, Engineering Safety Features - Residual Heat Removal - Aging Management Evaluation.

2.3.2.4 Safety Injection

System Description

The safety injection system is designed to provide emergency cooling to the reactor core and to provide adequate shutdown margin in the event of a loss of coolant accident. The safety injection system includes high-head injection pumps, low-head injection pumps, and hydro-pneumatic accumulator tanks that provide injection of borated water into the reactor coolant system. The pumps also provide the capability to remove reactor core decay heat for extended periods following an accident. This is accomplished by recirculating coolant, cooled by the recirculation spray system, from the containment sump through the core.

The UFSAR also refers to the safety injection system as the emergency core cooling system (ECCS).

System Evaluation Boundary

The evaluation boundary for the safety injection system components that are subject to aging management review includes the safety-related flowpaths from the refueling water storage tanks and from the containment sump strainers through the low-head safety injection pumps to the reactor coolant system; the suction flowpaths to the charging pump suctions from the refueling water storage tank and from the low-head safety injection pumps; the flowpaths from the charging pump discharges to the reactor coolant system; and the accumulators, the accumulator fill, drain and test lines, and their discharge flowpaths to the reactor coolant system. Additionally, nonsafety-related fluid filled piping, and nonsafety-related piping directly attached to safety-related piping is subject to aging management review.

The high-head safety injection pumps provide a dual function as charging pumps and are evaluated for the effects of aging with the chemical and volume control system components.

System Intended Functions

The safety injection system performs the following safety-related functions: The system provides cool borated water to the reactor coolant system following a design basis event to mitigate fuel cladding damage and to maintain the reactor shutdown; provides non-EQ safety-related instrumentation; and provides containment isolation. Therefore, the safety injection system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The safety injection system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the safety injection system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The safety injection system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Environmental Qualification (10 CFR 50.49). Therefore, the safety injection system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the safety injection system can be found in the UFSAR, Section 6.3 and Table 6.2-37.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the safety injection system are listed below:

11715-SLRM-096A Sh. 1

11715-SLRM-096A Sh. 2

11715-SLRM-096A Sh. 3

11715-SLRM-096B Sh. 1

11715-SLRM-096B Sh. 2

11715-SLRM-096B Sh. 3

11715-SLRM-096B Sh. 4

12050-SLRM-096A Sh. 1

12050-SLRM-096A Sh. 2

12050-SLRM-096A Sh. 3

12050-SLRM-096B Sh. 1

12050-SLRM-096B Sh. 2

12050-SLRM-096B Sh. 3

12050-SLRM-096B Sh. 4

12050-SLRM-096C Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.2-4, Safety Injection.

The aging management review results for these component types are indicated in Table 3.2.2-4, Engineering Safety Features - Safety Injection - Aging Management Evaluation.

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Screening Results Tables: Engineered Safety Features Systems

Table 2.3.2-1 Quench Spray

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Heat exchanger (refueling water refrigeration unit - base mounted evaporator/cooler)	Structural Integrity (Attached)
Insulation (safety-related heat traced components)	Thermal insulation
Orifice	Pressure Boundary, Restricts Flow, Structural Integrity (Attached)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Piping, piping components (exiting concrete into soil)	Pressure Boundary
Pump casing (chemical addition tank recirculation)	Structural Integrity (Attached)
Pump casing (quench spray)	Pressure Boundary
Pump casing (refueling water recirculation)	Leakage Boundary (Spatial)
Spray nozzle	Spray Pattern
Strainer body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Strainer element	Filtration
Tank (chemical addition)	Pressure Boundary
Tank (refueling water storage)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

See Table 2.1-1 for definitions of intended functions.

The aging management review results for these component types are indicated in Table 3.2.2-1 Engineering Safety Features - Quench Spray - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.2-2 Recirculation Spray

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Heat exchanger (casing cooling tank chiller - shell)	Leakage Boundary (Spatial)
Heat exchanger (recirculation spray - channel)	Pressure Boundary
Heat exchanger (recirculation spray - shell)	Pressure Boundary
Heat exchanger (recirculation spray - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (recirculation spray - tubesheet)	Pressure Boundary
Heat exchanger (seal cooler - tube)	Heat Transfer, Pressure Boundary
Orifice	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Piping, piping components (exiting concrete into soil)	Pressure Boundary
Pump casing (casing cooling tank recirculation)	Leakage Boundary (Spatial)
Pump casing (casing cooling)	Pressure Boundary
Pump casing (recirculation spray)	Pressure Boundary
Spray nozzle	Spray Pattern
Strainer body	Leakage Boundary (Spatial)
Strainer element (containment sump)	Filtration

See Table 2.1-1 for definitions of intended functions.

Table 2.3.2-2 Recirculation Spray

Component Type	Intended Function(s)
Tank (casing cooling)	Pressure Boundary
Tank (seal accumulator)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.2.2-2 Engineering Safety Features - Recirculation Spray - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.2-3 Residual Heat Removal

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Heat exchanger (residual heat removal - channel)	Pressure Boundary
Heat exchanger (residual heat removal - shell)	Pressure Boundary
Heat exchanger (residual heat removal - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (residual heat removal - tubesheet)	Pressure Boundary
Heat exchanger (seal cooler - housing)	Pressure Boundary
Heat exchanger (seal cooler - tube)	Heat Transfer, Pressure Boundary
Orifice	Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Piping, piping components (Class 1)	Pressure Boundary
Piping, piping components (exiting concrete into soil)	Pressure Boundary
Pump casing (residual heat removal)	Pressure Boundary
Valve body	Pressure Boundary
Valve body (Class 1)	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.2.2-3 Engineering Safety Features - Residual Heat Removal - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.2-4 Safety Injection

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Insulation (safety-related heat traced components)	Thermal insulation
Orifice	Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Piping, piping components (Class 1 <NPS 4)	Pressure Boundary
Piping, piping components (Class 1)	Pressure Boundary
Piping, piping components (exiting concrete into soil)	Pressure Boundary
Pump casing (hydro test)	Pressure Boundary
Pump casing (low-head safety injection)	Pressure Boundary
Sample sink	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Strainer body	Pressure Boundary
Strainer element	Filtration
Strainer element (containment sump)	Filtration
Tank (boron injection)	Pressure Boundary
Tank (hydro test cooling)	Leakage Boundary (Spatial)
Tank (safety injection accumulator)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.2-4 Safety Injection

Component Type	Intended Function(s)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Valve body (Class 1)	Pressure Boundary
Venturi	Pressure Boundary, Restricts Flow

The aging management review results for these component types are indicated in Table 3.2.2-4 Engineering Safety Features - Safety Injection - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

2.3.3 AUXILIARY SYSTEMS

2.3.3.1 Fuel Pit Cooling

System Description

The fuel pit cooling system transfers heat from the spent fuel pit (also called the spent fuel pool) to the component cooling system. The fuel pit cooling system recirculates borated water from the spent fuel pit through the spent fuel pit heat exchangers and back to the pit. The pump suction connection to the spent fuel pit is at an elevation that prevents draining the pit below the limiting water level in the event of a leak in the system.

System Evaluation Boundary

The evaluation boundary for the fuel pit cooling system components subject to aging management review includes the piping and components in the cooling flowpath from the spent fuel pit through the spent fuel cooling pumps and heat exchangers and the return to the fuel pit. Also subject to aging management review are the nonsafety-related components that retain water in buildings containing safety-related components or that provide support to safety-related piping. This includes the fuel cask pumpdown pump and associated piping components to and from the cask area, fuel storage area and transfer canal that are not depicted on license renewal drawings. The spent fuel pit skimmers are not within-scope because they do not support an intended function; they are nonsafety-related, they do not provide support to safety-related piping, and their pressure boundaries are within the pit. The internal portions of the skimmers are at or below ambient pressure, such that loss of integrity could not result in external leakage that could result in loss of a safety-related function. The fuel pit liner and storage racks are evaluated in the structural section of the SLRA.

System Intended Functions

The fuel pit cooling system performs the following safety-related function: The system removes heat from the spent fuel pit. Therefore, the fuel pit cooling system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The fuel pit cooling system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the fuel pit cooling system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

UFSAR References

Additional details of the fuel pit cooling system can be found in the UFSAR, Section 9.1.3 and Table 9.1-1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the fuel pit cooling system are listed below:

11715-SLRM-088A Sh. 4

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-1, Fuel Pit Cooling.

The aging management review results for these component types are indicated in Table 3.3.2-1, Auxiliary Systems - Fuel Pit Cooling - Aging Management Evaluation.

2.3.3.2 Refueling Purification

System Description

The refueling purification system provides a means to maintain the water quality of the spent fuel pit, the reactor cavities during refueling operations, and the refueling water storage tanks. The system also includes the capability to pump reactor cavity water to the refueling water storage tank.

System Evaluation Boundary

The evaluation boundary for the refueling purification system components subject to aging management review includes safety-related containment penetration piping components and safety-related piping components that provide a pressure boundary for connected systems; nonsafety-related piping components that provide a pressure boundary for the reactor cavity (when filled), and nonsafety-related pumps and components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components.

System Intended Functions

The refueling purification system performs the following safety-related functions: The system provides containment isolation and provides safety-related pressure boundary integrity for connected safety-related systems. Therefore, the refueling purification system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The refueling purification system contains nonsafety-related components that provide a pressure boundary for the reactor cavity (when filled), and also contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the refueling purification system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for refueling cavity integrity and for spatial interaction and structural integrity.

UFSAR References

Additional details of the refueling purification system can be found in the UFSAR, Section 9.1.3 and Table 9.1-1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the refueling purification system are listed below:

11715-SLRM-088A Sh. 1

11715-SLRM-088A Sh. 2

11715-SLRM-088A Sh. 3

11715-SLRM-088A Sh. 4

11715-SLRM-088A Sh. 5

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-2, Refueling Purification.

The aging management review results for these component types are indicated in Table 3.3.2-2, Auxiliary Systems - Refueling Purification - Aging Management Evaluation.

2.3.3.3 Primary Grade Water

System Description

The primary grade water system is a subsystem of the boron recovery system and provides treated water to plant systems for various uses, such as flush water for demineralizers and chemical addition to the chemical and volume control system, blender supply and makeup, makeup to the pressurizer relief tank, seal water for small pumps, and other miscellaneous uses. Portions of the primary grade water system provide a pressure boundary for the reactor coolant system.

System Evaluation Boundary

Portions of the primary grade water system subject to aging management review include the safety-related piping connecting to the pressurizer relief tank, and nonsafety-related piping providing support to attached safety-related piping. The water-filled piping components within buildings containing safety-related components are also subject to aging management review.

System Intended Functions

The primary grade water system performs the following safety-related functions: The system provides a pressure boundary function for reactor coolant system piping connecting to the pressurizer relief tank. Therefore, the primary grade water system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The primary grade water system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the primary grade water system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

UFSAR References

Additional details of the primary grade water system can be found in the UFSAR, Section 9.3.5.2 and Table 9.3-7.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the primary grade water system are listed below:

11715-SLRM-086C Sh. 1

11715-SLRM-086C Sh. 2

11715-SLRM-086C Sh. 3

11715-SLRM-086C Sh. 4

11715-SLRM-086D Sh. 1

11715-SLRM-086D Sh. 2

11715-SLRM-086D Sh. 3

11715-SLRM-093B Sh. 2

11715-SLRM-095B Sh. 1

11715-SLRM-096A Sh. 3

12050-SLRM-093B Sh. 2

12050-SLRM-095B Sh. 1

12050-SLRM-096A Sh. 3

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-3, Primary Grade Water.

The aging management review results for these component types are indicated in Table 3.3.2-3, Auxiliary Systems - Primary Grade Water - Aging Management Evaluation.

2.3.3.4 Helium Vacuum Drying

System Description

The helium vacuum drying system supports dewatering and vacuum drying of the fuel storage dry shielded canisters, followed by backfilling the casks with helium.

System Evaluation Boundary

The evaluation boundary for the helium vacuum drying system components subject to aging management review includes the nonsafety-related piping components that retain water in buildings containing safety-related components.

System Intended Functions

The helium vacuum drying system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the helium vacuum drying system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

UFSAR References

Additional details of the helium vacuum drying system can be found in the UFSAR, Section 9.5.9.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the helium vacuum drying system are listed below:

11715-SLRM-114A Sh. 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-4, Helium Vacuum Drying.

The aging management review results for these component types are indicated in Table 3.3.2-4, Auxiliary Systems - Helium Vacuum Drying - Aging Management Evaluation.

2.3.3.5 Fuel Handling

System Description

The fuel handling system provides for safe handling of new and spent fuel assemblies during refueling operations and postulated accidents. The system includes the fuel transfer tubes and gate valves. In addition, the system includes the removable reactor cavity seal rings, which provide a pressure boundary for the annular space between the reactor vessel flange and the refueling cavity liner to retain the refueling cavity water inventory during refueling. The system also encompasses equipment utilized to support independent spent fuel storage installation operations regulated by 10 CFR 72.

System Evaluation Boundary

The evaluation boundary for the fuel handling system components subject to aging management review includes the fuel transfer tube assemblies, gate valves and the reactor cavity seal rings. Cranes and hoists within the scope of subsequent license renewal are addressed in the materials handling system.

System Intended Functions

The fuel handling system performs the following safety-related functions: The system provides containment isolation and provides a pressure boundary for the spent fuel pool. The system also provides a pressure boundary to retain inventory in the refueling cavity during refueling. Therefore, the fuel handling system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

UFSAR References

Additional details of the fuel handling system can be found in the UFSAR, Sections 6.2.4.2, 9.1.2, 9.1.4.3.1, 9.1.4.3.2, and 9.1.4.6.3, and Table 6.2-37.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the fuel handling system are listed below:

11715-SLRM-088A Sh. 2

11715-SLRM-088A Sh. 3

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-5, Fuel Handling.

The aging management review results for these component types are indicated in Table 3.3.2-5, Auxiliary Systems - Fuel Handling - Aging Management Evaluation.

2.3.3.6 Materials Handling

System Description

The materials handling system is comprised of load handling cranes, hoists and lifting devices. Included in the evaluation boundary of the cranes and hoists system is load handling equipment in various areas of the facility. The following cranes and hoists that are within the scope of NUREG-0612 are within-scope for subsequent license renewal:

- Containment polar cranes
- Containment annulus hoists
- Residual heat removal pump monorails
- Fuel Building movable platform
- Fuel Building trolley
- Auxiliary Building monorails

Other cranes and hoists that are not within the scope of NUREG-0612, but are used to lift fuel assemblies or other loads within containment are also within the scope of subsequent license renewal. As a result, the following cranes and hoists are within-scope for subsequent license renewal:

- Refueling manipulator cranes
- New fuel transfer elevator
- Containment jib cranes

In addition to the cranes and hoists listed above, the following lifting devices are within the scope of NUREG-0612 and are within the scope of subsequent license renewal:

- Reactor vessel head lifting device
- Reactor internals lifting rig
- Reactor coolant pump motor lift rig
- Reactor cavity seal lift rig
- Spent filter cask spreader beam
- Spent fuel cask lifting yoke (called “beam” in the UFSAR)
- Long cask lid lifting tool
- Short cask lid lifting tool
- Reactor vessel head stud racks
- Charging pump cubicle wall lifting beam
- Reactor cavity seal ring flip rig

System Evaluation Boundary

The evaluation boundary for the materials handling system components subject to aging management review includes load-bearing elements that support the load in a passive manner. These include the structural bolting, beams, girders, plates, rails and retaining clips associated with the cranes and hoists listed above; and the passive lifting devices listed above.

System Intended Functions

The materials handling system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the materials handling system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for structural support.

UFSAR References

Additional details of the materials handling system can be found in the UFSAR, Sections 9.1.2, 9.1.4, and 9.6.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the materials handling system.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-6, Materials Handling.

The aging management review results for these component types are indicated in Table 3.3.2-6, Auxiliary Systems - Materials Handling - Aging Management Evaluation.

2.3.3.7 Service Water

System Description

The service water system transfers heat from plant systems and components to the ultimate heat sink provided by the Service Water Reservoir or the North Anna reservoir. The service water system removes heat from the component cooling water system, the recirculation spray system, the charging pump lubricating oil, the instrument air compressors, and the main control room air-conditioning chiller condensers. The normal source of service water is the man-made nine-acre Service Water Reservoir. Service water is pumped from the reservoir, treated with corrosion inhibitors and biocides, circulated through the serviced loads, and then returned to the reservoir through spray nozzles for evaporative cooling. The spray system has a bypass capability for cold weather operation, when evaporative cooling is not required. Water from the North Anna reservoir is an alternate source of service water and is the normal source of make-up supply to the Service Water Reservoir.

System Evaluation Boundary

The evaluation boundary for the service water system components subject to aging management review includes the service water and auxiliary service water pumps with associated auxiliary equipment, including the Service Water Reservoir spray arrays; and piping and components that provide cooling water to and from the recirculation spray heat exchangers, the component cooling heat exchangers, the control and relay room chiller condensers, the instrument air cooling water heat exchangers, and the charging pump lubricating oil and gearbox coolers. The evaluation boundary also includes nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components.

System Intended Functions

The service water system performs the following safety-related functions: The system provides cooling water to safety-related components, provides non-EQ safety-related instrumentation, and provides containment isolation. Therefore, the service water system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The service water system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the service water system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The service water system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), and Station Blackout (10 CFR 50.63). Therefore, the service water system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the service water system can be found in the UFSAR, Section 9.2.1 and Table 9.2-4.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the service water system are listed below:

11715-SLRB-040D Sh. 1

11715-SLRB-040D Sh. 2

11715-SLRM-078A Sh. 1

11715-SLRM-078A Sh. 2

11715-SLRM-078A Sh. 3

11715-SLRM-078A Sh. 4

11715-SLRM-078A Sh. 5

11715-SLRM-078B Sh. 1

11715-SLRM-078B Sh. 3

11715-SLRM-078C Sh. 1

11715-SLRM-078C Sh. 2

11715-SLRM-078G Sh. 1

11715-SLRM-078G Sh. 2

11715-SLRM-078H Sh. 1

11715-SLRM-078J Sh. 1

11715-SLRM-078K Sh. 1

11715-SLRM-078L Sh. 1

11715-SLRM-078L Sh. 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-7, Service Water.

The aging management review results for these component types are indicated in Table 3.3.2-7, Auxiliary Systems - Service Water - Aging Management Evaluation.

2.3.3.8 Bearing Cooling

System Description

The bearing cooling system is an intermediate cooling system that supplies cooling water to nonsafety-related steam and power conversion system components. The system is normally operated as a closed-loop cooling system that uses an induced-draft cooling tower consisting of four cells (two cells per unit) erected over a common cold-water basin. The system may also be operated in a once-through mode, taking suction from the circulating water intake tunnel in the Turbine Building and discharging to the circulating water discharge tunnel. The system is provided with a chemical addition system and sample points for corrosion control.

System Evaluation Boundary

The evaluation boundary for the bearing cooling system components subject to aging management review includes the nonsafety-related water-retaining components within buildings containing safety-related components. These nonsafety-related components include main bearing cooling pumps, the bearing cooling makeup pumps, chemical addition tanks, and distribution piping components and valves supplying various heat exchangers associated with other systems in the Turbine and Service Buildings and Mechanical Equipment Rooms, as well as makeup supplies to various systems in these areas.

The bearing cooling system cooling towers are located outside the protected area, and are, therefore, not in-scope.

System Intended Functions

The bearing cooling system contains nonsafety-related components that provide a functional pressure boundary for the service water system, and portions also contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the bearing cooling system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

UFSAR References

Additional details of the bearing cooling system can be found in the UFSAR, Section 10.4.7 and Table 10.4-6.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the bearing cooling system are listed below:

11715-SLRB-040C Sh. 3

11715-SLRB-040D Sh. 1

11715-SLRB-040D Sh. 3

11715-SLRM-080A Sh. 1

11715-SLRM-080A Sh. 2

11715-SLRM-080B Sh. 1

11715-SLRM-080C Sh. 1

11715-SLRM-081A Sh. 1

11715-SLRM-089F Sh. 2

12050-SLRM-080A Sh. 1

12050-SLRM-080A Sh. 2

12050-SLRM-080B Sh. 1

12050-SLRM-081A Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-8, Bearing Cooling.

The aging management review results for these component types are indicated in Table 3.3.2-8, Auxiliary Systems - Bearing Cooling - Aging Management Evaluation.

2.3.3.9 Circulating Water

System Description

The circulating water system is supplied from the North Anna reservoir and provides cooling water for the main condenser. Circulating water is taken from the North Anna reservoir on the north side of the station and, after passing through the condenser, is discharged into the Waste Heat Treatment Facility to dissipate a large portion of the heat before returning to the reservoir. The circulating water system also provides makeup from the Intake Structure to the Service Water Reservoir.

System Evaluation Boundary

The evaluation boundary for the circulating water system components subject to aging management review includes the safety-related screen wash pumps and the piping and components in the discharge path to the Service Water Reservoir, and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components, including the condenser water boxes and the condenser tube cleaning subsystem. Other portions of the condenser (i.e., the hotwell) are evaluated in the condensate system. The condenser tubes do not perform an intended function for subsequent license renewal and are, therefore, not in-scope.

Additionally, the circulating water intake tunnel does not perform an intended function for subsequent license renewal and is, therefore, not in-scope. The circulating water discharge tunnel is in-scope and is evaluated as a structural component.

System Intended Functions

The circulating water system performs the following safety-related functions: The safety-related screen wash pump and discharge piping provide makeup to the Service Water Reservoir. The system also provides non-EQ safety-related instrumentation, including signals to trip the circulating water pumps and stop flow upon sensing Turbine Building flooding. Therefore, the circulating water system is within the scope of subsequent license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The circulating water system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the circulating water system is within the scope of subsequent license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

UFSAR References

Additional details of the circulating water system can be found in the UFSAR, Section 10.4.2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the circulating water system are listed below:

11715-SLRM-077A Sh. 1

11715-SLRM-077A Sh. 2

11715-SLRM-99A Sh. 1

12050-SLRM-077A Sh. 1

12050-SLRM-077A Sh. 2

12050-SLRM-99A Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-9, Circulating Water.

The aging management review results for these component types are indicated in Table 3.3.2-9, Auxiliary Systems - Circulating Water - Aging Management Evaluation.

2.3.3.10 Vacuum Priming

System Description

The vacuum priming system removes non-condensable gases from various plant systems, including the condensate system (condenser waterboxes, discharge tunnel) and bearing cooling system (pump casings and suction lines).

System Evaluation Boundary

The evaluation boundary for the vacuum priming system components subject to aging management review includes the safety-related containment isolation components, and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components.

System Intended Functions

The vacuum priming system performs the following safety-related functions: The system provides containment isolation, and provides non-EQ safety-related instrumentation. Therefore, the vacuum priming system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The vacuum priming system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the vacuum priming system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

UFSAR References

Additional details of the vacuum priming system can be found in the UFSAR, Section 10.4.2.2 and Table 6.2-37.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the vacuum priming system are listed below:

11715-SLRM-072A Sh. 1

11715-SLRM-072A Sh. 2

11715-SLRM-081A Sh. 1

12050-SLRM-072A Sh. 1

12050-SLRM-072A Sh. 2

12050-SLRM-081A Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-10, Vacuum Priming.

The aging management review results for these component types are indicated in Table 3.3.2-10, Auxiliary Systems - Vacuum Priming - Aging Management Evaluation.

2.3.3.11 Domestic Water

System Description

The domestic water system provides potable water to lavatories, laundry facilities, drinking fountains, eyewash/shower stations, hose connections, makeup to main control room chillers chilled water system, and makeup to front office chillers chilled water system.

System Evaluation Boundary

The evaluation boundary for the domestic water system components subject to aging management review includes the nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components.

System Intended Functions

The domestic water system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the domestic water system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

UFSAR References

Additional details of the domestic water system can be found in the UFSAR, Section 9.2.3.1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the domestic water system are listed below:

11715-SLRB-040C Sh. 3

11715-SLRB-041C Sh. 1

11715-SLRB-041C Sh. 2

11715-SLRB-041D Sh. 5

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-11, Domestic Water.

The aging management review results for these component types are indicated in Table 3.3.2-11, Auxiliary Systems - Domestic Water - Aging Management Evaluation.

2.3.3.12 Component Cooling

System Description

The component cooling system is an intermediate cooling system that transfers heat from plant primary systems and components to the service water system via the component cooling heat exchangers. The component cooling system serves safety-related and nonsafety-related systems and components that contain potentially radioactive fluids. The component cooling system is a closed cooling water system, cross-connected to serve both units, and utilizing a corrosion inhibitor.

System Evaluation Boundary

The evaluation boundary for the component cooling system components subject to aging management review includes piping and components in the safety-related flowpaths from the component cooling surge tank, through the component cooling pumps and heat exchangers, to the various loads (heat exchangers) throughout the plant, and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components.

Coolers and heat exchangers in other systems that are cooled by component cooling water are evaluated with their parent systems.

System Intended Functions

The component cooling system performs the following safety-related functions: The system provides cooling water and a system pressure boundary function to support operation of various systems, provides non-EQ safety-related instrumentation, and provides containment isolation. Therefore, the component cooling system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The component cooling system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the component cooling system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The component cooling system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), and Station Blackout (10 CFR 50.63). Therefore, the component cooling system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the component cooling system can be found in the UFSAR, Section 9.2.2 and Table 9.2-5.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the component cooling system are listed below:

11715-SLRM-079A Sh. 1

11715-SLRM-079A Sh. 2

11715-SLRM-079A Sh. 3

11715-SLRM-079B Sh. 1

11715-SLRM-079B Sh. 2

11715-SLRM-079B Sh. 3

11715-SLRM-079B Sh. 4

11715-SLRM-079B Sh. 5

11715-SLRM-079C Sh. 1

11715-SLRM-079C Sh. 2

11715-SLRM-079C Sh. 3

11715-SLRM-079C Sh. 4

11715-SLRM-079C Sh. 5

11715-SLRM-079D Sh. 3

11715-SLRM-079D Sh. 4

12050-SLRM-079A Sh. 1

12050-SLRM-079A Sh. 2

12050-SLRM-079A Sh. 3

12050-SLRM-079A Sh. 4

12050-SLRM-079A Sh. 5

12050-SLRM-079B Sh. 3

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-12, Component Cooling.

The aging management review results for these component types are indicated in Table 3.3.2-12, Auxiliary Systems - Component Cooling - Aging Management Evaluation.

2.3.3.13 Neutron Shield Tank Cooling

System Description

The neutron shield tank cooling system provides cooling for the neutron shield tank fluid which is heated by attenuation of neutron and gamma radiation in the vicinity of the reactor vessel. Neutron shield tank cooling system cooling water is provided by the component cooling system.

The heated water in the neutron shield tanks is cooled as it is pumped through one of the two neutron shield tank coolers by one of the two neutron shield cooling tank pumps, or by natural circulation using both neutron shield tank coolers. A surge tank accommodates thermal expansion of the neutron shield tank cooling system water and maintains the neutron shield tank full with makeup from the component cooling system.

System Evaluation Boundary

The evaluation boundary for the neutron shield tank cooling water system components subject to aging management review includes the safety-related coolers and associated piping and components, and the nonsafety-related shield tank cooling loop consisting of pumps, surge tanks, and associated flowpath piping and components, and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components. The neutron shield tank itself is evaluated with the reactor coolant system, and its structural support function is further described in the structural commodities (NSSS supports) section.

System Intended Functions

The neutron shield tank cooling system performs the following safety-related functions: The system performs a pressure boundary function to ensure the integrity of the safety-related component cooling system. Therefore, the neutron shield tank cooling system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The neutron shield tank cooling system removes heat from the neutron shield tank and contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the neutron shield tank cooling system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for heat removal and for spatial interaction and structural integrity.

UFSAR References

Additional details of the neutron shield tank cooling system can be found in the UFSAR, Section 9.2.2 and Table 9.2-7.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the neutron shield tank cooling system are listed below:

11715-SLRM-079B Sh. 5

12050-SLRM-079A Sh. 5

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-13, Neutron Shield Tank Cooling.

The aging management review results for these component types are indicated in Table 3.3.2-13, Auxiliary Systems - Neutron Shield Tank Cooling - Aging Management Evaluation.

2.3.3.14 Instrument Air

System Description

The instrument air system provides a reliable source of clean, dry, oil-free compressed air to air-operated valves, instruments, and other miscellaneous components in the plant. Critical components that require compressed air in order to perform intended functions are provided with back-up subsystems and do not rely upon the normal instrument air system as the sole source of compressed air.

The following air-operated components are provided with back-up compressed gas supplies (via the primary and secondary plant gas supply system):

- Pressurizer power-operated relief valves
- Containment hydrogen recombiner trip valves

The following air-operated components are provided with back-up air storage tanks:

- Selected feedwater valves
- Selected ventilation system dampers
- Main steam power-operated relief valves
- Main steam supply valves for the auxiliary feedwater turbines

The system includes stored gas bottles, hose, and valves to support local operation of the following air-operated valves following a fire:

- Selected component cooling valves
- Selected residual heat removal valves

System Evaluation Boundary

The evaluation boundary for the instrument air system components subject to aging management review includes the safety-related containment penetration piping and isolation valves, the air or gas supply to selected air-operated valves and dampers, the instrument air compressor heat exchangers, the nonsafety-related components that provide support to directly-connected safety-related components, and the components associated with air compressors or drain traps (at air receivers and air dryers) that retain water or oil in buildings containing safety-related components. Also subject to aging management are the stored gas bottles, hose, and valves used to support local operation of air-operated valves.

System Intended Functions

The instrument air system performs the following safety-related functions: The system provides containment isolation, provides non-EQ safety-related instrumentation, provides a pressure boundary for the service water system, and provides a backup air or gas supply to support the safety-related functions of select air-operated valves. Therefore, the instrument air system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The instrument air system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the instrument air system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The instrument air system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), and Station Blackout (10 CFR 50.63). Therefore, the instrument air system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the instrument air system can be found in the UFSAR, Section 9.3.1 and Table 6.2-37.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the instrument air system are listed below:

11715-SLRM-082A Sh. 1

11715-SLRM-082A Sh. 2

11715-SLRM-082A Sh. 3

11715-SLRM-082B Sh. 1

11715-SLRM-082B Sh. 2

11715-SLRM-082B Sh. 3

11715-SLRM-082B Sh. 4

11715-SLRM-082C Sh. 1

11715-SLRM-082C Sh. 2

11715-SLRM-082M Sh. 1

11715-SLRM-082N Sh. 1

11715-SLRM-082N Sh. 2

12050-SLRM-082A Sh. 1

12050-SLRM-082A Sh. 2

12050-SLRM-082A Sh. 3

12050-SLRM-082B Sh. 1

12050-SLRM-082B Sh. 2

12050-SLRM-082C Sh. 1

12050-SLRM-082C Sh. 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-14, Instrument Air.

The aging management review results for these component types are indicated in Table 3.3.2-14, Auxiliary Systems - Instrument Air - Aging Management Evaluation.

2.3.3.15 Service Air

System Description

The service air system provides a source of compressed air to support plant general service compressed air requirements. The service air system can be used as a source of compressed air to the instrument air system.

System Evaluation Boundary

The evaluation boundary for the service air system components subject to aging management review includes the containment penetration piping and isolation valves, the associated directly-connected nonsafety-related components that provide support to these safety-related components, and moisture traps and associated fluid-retaining piping components in buildings containing safety-related components.

System Intended Functions

The service air system performs the following safety-related function: The system provides containment isolation. Therefore, the service air system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The service air system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the service air system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

UFSAR References

Additional details of the service air system can be found in the UFSAR, Section 9.3.1 and Table 6.2-37.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the service air system are listed below:

11715-SLRM-082B Sh. 1

11715-SLRM-082B Sh. 2

11715-SLRM-082B Sh. 3

11715-SLRM-082F Sh. 1

12050-SLRM-082F Sh. 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-15, Service Air.

The aging management review results for these component types are indicated in Table 3.3.2-15, Auxiliary Systems - Service Air - Aging Management Evaluation.

2.3.3.16 Primary & Secondary Plant Gas Supplies

System Description

The primary and secondary plant gas supply system provides compressed gas for various plant uses.

System Evaluation Boundary

The evaluation boundary for the primary and secondary plant gas supply system that is subject to aging management review consists of the components that provide compressed gas in support of the operation of the hydrogen analyzer system; that provide a backup pneumatic source for the hydrogen recombiner valves and the pressurizer power-operated relief valves; and that perform a pressure boundary function for the main steam system. Additionally, the nonsafety-related components that provide support to directly-connected safety-related components, or that retain water or steam in buildings containing safety-related components are subject to aging management review.

System Intended Functions

The primary and secondary plant gas supply system performs the following safety-related functions: The system provides gas for operation of the pressurizer power-operated relief valves and hydrogen recombiner trip valves; provides gas for the post-accident hydrogen analyzers; provides hydrogen to the volume control tanks; and provides a pressure boundary for the main steam system. Therefore, the primary and secondary plant gas supply system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The primary and secondary plant gas supply system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the primary and secondary plant gas supply system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

UFSAR References

Additional details of the primary & secondary plant gas supplies system can be found in the UFSAR, Sections 5.5.8.2, 6.2.5.2, and 9.5.10.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the primary & secondary plant gas supplies system are listed below:

11715-SLRM-105A Sh. 1

11715-SLRM-105A Sh. 2

11715-SLRM-105A Sh. 3

11715-SLRM-105B Sh. 1

11715-SLRM-105B Sh. 2

11715-SLRM-105B Sh. 3

11715-SLRM-105C Sh. 1

11715-SLRM-106A Sh. 1

11715-SLRM-106A Sh. 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-16, Primary & Secondary Plant Gas Supplies.

The aging management review results for these component types are indicated in Table 3.3.2-16, Auxiliary Systems - Primary & Secondary Plant Gas Supplies - Aging Management Evaluation.

2.3.3.17 Penetration Electrical

System Description

The penetrations electrical system provides penetrations through Containment for electrical systems while maintaining containment integrity. The penetrations electrical system includes pressure gages and associated valves and piping (tubing) for maintaining the electrical penetrations pressurized.

System Evaluation Boundary

The evaluation boundary for the penetrations electrical system components subject to aging management review includes only the electrical penetration pressurization piping and valves.

The penetration assemblies themselves are evaluated as structural commodities. The electrical cables associated with electrical penetrations are evaluated in the electrical section.

System Intended Functions

The penetrations electrical system performs the following safety-related functions: The system provides containment integrity. Therefore, the penetrations electrical system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The penetrations electrical system is relied upon for compliance with regulations for Environmental Qualification (10 CFR 50.49). Therefore, the penetrations electrical system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the penetration electrical system can be found in the UFSAR, Section 3.8.2.1.4.1.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the penetration electrical system.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-17, Penetration Electrical.

The aging management review results for these component types are indicated in Table 3.3.2-17, Auxiliary Systems - Penetration Electrical - Aging Management Evaluation.

2.3.3.18 Leakage Monitoring

System Description

The leakage monitoring system provides containment pressure signals used to generate engineered safety features actuations. The system is also designed to provide pressure sensing during containment leakrate testing.

System Evaluation Boundary

The evaluation boundary for the leakage monitoring system components subject to aging management review includes the safety-related containment isolation components, and nonsafety-related components that provide support to directly-connected safety-related components.

System Intended Functions

The leakage monitoring system performs the following safety-related functions: The system provides containment isolation, and provides non-EQ safety-related instrumentation. Therefore, the leakage monitoring system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The leakage monitoring system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the leakage monitoring system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for structural integrity.

The leakage monitoring system is relied upon for compliance with regulations for Environmental Qualification (10 CFR 50.49). Therefore, the leakage monitoring system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the leakage monitoring system can be found in the UFSAR, Section 6.2.7 and Table 6.2-37.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the leakage monitoring system are listed below:

11715-SLRM-092A Sh. 1

12050-SLRM-092A Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-18, Leakage Monitoring.

The aging management review results for these component types are indicated in Table 3.3.2-18, Auxiliary Systems - Leakage Monitoring - Aging Management Evaluation.

2.3.3.19 Chemical & Volume Control

System Description

The chemical and volume control system provides reactor coolant system letdown and make-up for chemistry control and purification of reactor coolant system fluid and control of chemical shim concentration for reactivity control. The system also provides reactor coolant pump seal injection flow, processing of reactor coolant pump seal leak-off flow, and reactor coolant system pressurizer level control. The chemical and volume control system charging pumps provide a dual function as the high-head safety injection pumps during emergency conditions. The system also includes chemical addition, boric acid batching, and borated water storage capability.

Portions of system are within the ASME Class 1 reactor coolant system pressure boundary.

System Evaluation Boundary

The evaluation boundary for the chemical and volume control system components subject to aging management review includes the letdown flowpath from the reactor coolant system through the regenerative and nonregenerative heat exchangers and letdown demineralizers to the volume control tank, the flowpaths from the volume control tank or refueling water storage tank through the charging pumps to the reactor coolant system; the boric acid tanks, pumps and flowpaths to the charging pump suction flowpath; the reactor coolant pump seal injection flowpath and leakoff flowpath through the seal water heat exchanger; the charging pump seal coolers and oil pumps, heat exchangers and flowpaths, and nonsafety-related components that retain water or steam in buildings containing safety-related components. Thermal insulation on letdown lines within containment penetrations is also subject to aging management review.

System Intended Functions

The chemical and volume control system performs the following safety-related functions: The system provides a pressure boundary for the reactor coolant system; provides containment isolation; provides for control of reactor coolant inventory and pressure; controls core reactivity; provides non-EQ safety-related instrumentation; provides reactor coolant pump seal injection flow; provides a flow path and the motive force for safety injection; and provides flow to the opposite unit chemical and volume control system. Therefore, the chemical and volume control system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The chemical and volume control system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the chemical and volume control system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The chemical and volume control system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), and Station Blackout (10 CFR 50.63). Therefore, the chemical and volume control system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the chemical & volume control system can be found in the UFSAR, Section 9.3.4 and Table 9.3-5.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the chemical & volume control system are listed below:

11715-SLRM-095A Sh. 1

11715-SLRM-095A Sh. 2

11715-SLRM-095A Sh. 3

11715-SLRM-095A Sh. 4

11715-SLRM-095B Sh. 1

11715-SLRM-095B Sh. 2

11715-SLRM-095C Sh. 1

11715-SLRM-095C Sh. 2

11715-SLRM-095D Sh. 1

11715-SLRM-095D Sh. 2

12050-SLRM-095A Sh. 1

12050-SLRM-095A Sh. 2

12050-SLRM-095B Sh. 1

12050-SLRM-095B Sh. 2

12050-SLRM-095C Sh. 1

12050-SLRM-095C Sh. 2

12050-SLRM-095D Sh. 1

12050-SLRM-095D Sh. 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-19, Chemical & Volume Control.

The aging management review results for these component types are indicated in Table 3.3.2-19, Auxiliary Systems - Chemical & Volume Control - Aging Management Evaluation.

2.3.3.20 Boron Recovery

System Description

The boron recovery system is a common system serving both units. The system degasifies and stores borated radioactive water letdown by the chemical and volume control system and reactor coolant drains transferred by the drains - gaseous system.

System Evaluation Boundary

The evaluation boundary for the boron recovery system components subject to aging management review includes safety-related boron recovery piping from chemical and volume control system letdown and from primary drains transfer tank, as well as safety-related heat exchangers and piping components that provide a pressure boundary for the component cooling system. Also subject to aging management review are nonsafety-related components that provide support to directly-connected safety-related components, or that retain water or steam in buildings containing safety-related components.

System Intended Functions

The boron recovery system performs the following safety-related functions: The system provides a pressure boundary for reactor coolant and for the component cooling system, and provides non-EQ safety-related instrumentation. Therefore, the boron recovery system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The boron recovery system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the boron recovery system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

UFSAR References

Additional details of the boron recovery system can be found in the UFSAR, Section 9.3.5 and Table 9.3-7.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the boron recovery system are listed below:

11715-SLRM-086A Sh. 1

11715-SLRM-086A Sh. 2

11715-SLRM-086A Sh. 3

11715-SLRM-086B Sh. 1

11715-SLRM-086B Sh. 2

11715-SLRM-086B Sh. 3

11715-SLRM-086C Sh. 2

11715-SLRM-086C Sh. 3

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-20, Boron Recovery.

The aging management review results for these component types are indicated in Table 3.3.2-20, Auxiliary Systems - Boron Recovery - Aging Management Evaluation.

2.3.3.21 Sampling System

System Description

The sampling system provides a means to monitor fluid quality and other system performance parameters for various plant systems. The sampling system consists of sample tubing and piping, valves, sample coolers, and other components that provide for the control of sample streams. Portions of the sampling system are within the ASME Class 1 reactor coolant system pressure boundary.

System Evaluation Boundary

The evaluation boundary for the sampling system components subject to aging management review includes safety-related piping from reactor coolant system and steam generator sample points within Containment through containment penetrations, and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water or steam in buildings containing safety-related components.

System Intended Functions

The sampling system performs the following safety-related functions: The system provides a reactor coolant pressure boundary, containment isolation and non-EQ safety-related instrumentation. Therefore, the sampling system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The sampling system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the sampling system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The sampling system is relied upon for compliance with regulations for Environmental Qualification (10 CFR 50.49) and Anticipated Transients Without Scram (10 CFR 50.62). Therefore, the sampling system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the sampling system can be found in the UFSAR, Section 9.3.2.1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the sampling system are listed below:

11715-SLRM-087C Sh. 1

11715-SLRM-089A Sh. 1

11715-SLRM-089A Sh. 2

11715-SLRM-089B Sh. 1

11715-SLRM-089B Sh. 2

11715-SLRM-089B Sh. 3

11715-SLRM-089B Sh. 4

11715-SLRM-089C Sh. 1

11715-SLRM-089D Sh. 1

11715-SLRM-089E Sh. 1

11715-SLRM-089F Sh. 1

11715-SLRM-089F Sh. 2

11715-SLRM-089F Sh. 3

11715-SLRM-089G Sh. 1

11715-SLRM-089G Sh. 2

11715-SLRM-089H Sh. 1

11715-SLRM-098A Sh. 1

11715-SLRM-103A Sh. 1

11715-SLRM-73A Sh. 1

12050-SLRM-089A Sh. 1

12050-SLRM-089A Sh. 2

12050-SLRM-089A Sh. 3

12050-SLRM-089A Sh. 4

12050-SLRM-089B Sh. 1

12050-SLRM-089C Sh. 1

12050-SLRM-089D Sh. 1

12050-SLRM-089D Sh. 2

12050-SLRM-089E Sh. 1

12050-SLRM-089E Sh. 2

12050-SLRM-089E Sh. 3

12050-SLRM-089F Sh. 1

12050-SLRM-098A Sh. 1

12050-SLRM-73A Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-21, Sampling System.

The aging management review results for these component types are indicated in Table 3.3.2-21, Auxiliary Systems - Sampling System - Aging Management Evaluation.

2.3.3.22 Incore Instrumentation

System Description

The incore instrumentation system provides reactor core performance information in the form of neutron flux distribution data. The system consists of thermocouples and retractable flux thimble tubes which are inserted through bottom mounted instrumentation guide tubes that penetrate the reactor vessel bottom head and then through selected fuel assembles, moveable incore neutron detectors which are inserted into the thimbles, a seal table with seal assemblies/fittings, and isolation valves. The guide tubes and seal table fittings form a pressure boundary for the reactor coolant system. The isolation valves normally do not provide a reactor coolant system pressure boundary, but are designed to be closed in the event of a leak in the system pressure boundary components. If closed, the isolation valves form the reactor coolant system pressure boundary.

System Evaluation Boundary

The evaluation boundary for the incore instrumentation system components subject to aging management review includes only the flux thimble tube isolation valves. The valves are not normally wetted, and do not rely on directly attached piping for support. The flux thimble tubes and plugs are evaluated with the reactor vessel internals system, and the bottom mounted instrumentation guide tubes, seal table, and seal table fittings are evaluated with the reactor vessel system. The detectors and drive cables are active components, not subject to aging management review.

System Intended Functions

The incore instrumentation system performs the following safety-related function: The system provides a pressure boundary for the reactor coolant system in the event of a flux thimble tube leak. Therefore, the incore instrumentation system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

UFSAR References

Additional details of the incore instrumentation system can be found in the UFSAR, Section 7.7.1.9.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the incore instrumentation system.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-22, Incore Instrumentation.

The aging management review results for these component types are indicated in Table 3.3.2-22, Auxiliary Systems - Incore Instrumentation - Aging Management Evaluation.

2.3.3.23 Decontamination

System Description

The decontamination system collects drainage from the Decontamination Building work areas and the building sump, provides for filtering and the addition of chemicals to the collected waste, and provides a means for transferring the collected waste to the liquid waste system or the fuel building sump.

System Evaluation Boundary

The evaluation boundary for the decontamination system components subject to aging management review includes the nonsafety-related components that retain water in buildings containing safety-related components.

System Intended Functions

The decontamination system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the decontamination system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

UFSAR References

Additional details of the decontamination system can be found in the UFSAR, Sections 9.5.9.2 and 9.5.9.3.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the decontamination system are listed below:

11715-SLRM-101A Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-23, Decontamination.

The aging management review results for these component types are indicated in Table 3.3.2-23, Auxiliary Systems - Decontamination - Aging Management Evaluation.

2.3.3.24 Drains - Aerated

System Description

The drains - aerated system collects potentially radioactive fluids, in which air is the predominant entrained gas, in building sumps and discharges the fluids to the waste disposal system for processing and disposal. Additionally, Containment Building sub-surface drain pumps minimize the hydrostatic pressure on the containment mat liner. The system includes floor drains in buildings containing radioactive fluids.

System Evaluation Boundary

The evaluation boundary for the drains - aerated system components subject to aging management review includes the safety-related containment penetration piping components; the nonsafety-related pumps and piping components within the containment base mat well that remove water from the containment base mat subsurface drains, and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water, steam or oil in buildings containing safety-related components.

System Intended Functions

The drains - aerated system performs the following safety-related functions: The system provides containment isolation and provides non-EQ safety-related instrumentation. Therefore, the drains - aerated system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The drains - aerated system removes water from the containment sub-surface drains to minimize hydrostatic pressure on the containment mat liner, and contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the drains - aerated system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for water removal, and for spatial interaction and structural integrity.

The drains - aerated system is relied upon for compliance with regulations for Environmental Qualification (10 CFR 50.49). Therefore, the drains - aerated system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the drains - aerated system can be found in the UFSAR, Sections 3.8.2.1.2.1 and 9.3.3, and Table 9.3-3.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the drains - aerated system are listed below:

11715-SLRM-090A Sh. 1

11715-SLRM-090A Sh. 2

11715-SLRM-090B Sh. 1

11715-SLRM-090C Sh. 3

12050-SLRM-090A Sh. 3

12050-SLRM-090B Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-24, Drains - Aerated.

The aging management review results for these component types are indicated in Table 3.3.2-24, Auxiliary Systems - Drains - Aerated - Aging Management Evaluation.

2.3.3.25 Drains - Building Services

System Description

The drains - building services system provides floor drain and roof drain piping, and sump pumps and discharge piping for non-radioactive fluids, and includes yard/storm drains.

System Evaluation Boundary

The evaluation boundary for the drains - building services system components subject to aging management review includes the safety-related chiller room sump pumps and cable vault check valves; nonsafety-related chiller room sump discharge piping and yard storm drain piping that provides flood protection, and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components.

Backflow preventers are not subject to aging management review because they are active components installed within floor drain piping, and do not have a passive pressure/leakage boundary function. The yard storm drains, roof drains, and some floor drain/ sump components do not appear on license renewal drawings.

System Intended Functions

The drains - building services system performs the following safety-related functions: Chiller room sump pumps and cable vault check valves prevent flooding in areas containing safety-related equipment. Therefore, the drains - building services system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The drains - building services system contains nonsafety-related components whose failure could result in flooding, or could prevent satisfactory accomplishment of a safety-related function. Therefore, the drains - building services system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for flood protection and for spatial interaction and structural integrity.

UFSAR References

Additional details of the drains - building services system can be found in the UFSAR, Sections 2.4.10 and 9.3.3.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the drains - building services system are listed below:

11715-SLRB-035A Sh. 2

11715-SLRB-201A Sh. 1

11715-SLRB-201A Sh. 2

11715-SLRB-201A Sh. 3

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-25, Drains - Building Services.

The aging management review results for these component types are indicated in Table 3.3.2-25, Auxiliary Systems - Drains - Building Services - Aging Management Evaluation.

2.3.3.26 Drains - Gaseous

System Description

The drains - gaseous system collects potentially radioactive fluids and discharges them to the boron recovery system. Drains collected from the primary systems are processed via the primary drains transfer tank and cooler.

System Evaluation Boundary

The evaluation boundary for the drains - gaseous system components subject to aging management review includes the safety-related piping components providing input to the system, the primary drain transfer cooler, primary drain transfer tank and pumps, and the flowpath through the discharge filter to the boron recovery system. Also subject to aging management review are the nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components.

System Intended Functions

The drains - gaseous system performs the following safety-related functions: The system provides containment isolation, provides a safety-related pressure boundary for radioactive fluids, and provides non-EQ safety-related instrumentation. Therefore, the drains - gaseous system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The drains - gaseous system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the drains - gaseous system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The drains - gaseous system is relied upon for compliance with regulations Environmental Qualification (10 CFR 50.49). Therefore, the drains - gaseous system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the drains - gaseous system can be found in the UFSAR, Section 9.3.3 and Table 9.3-3.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the drains - gaseous system are listed below:

11715-SLRM-090C Sh. 1

11715-SLRM-090C Sh. 2

12050-SLRM-090A Sh. 1

12050-SLRM-090A Sh. 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-26, Drains - Gaseous.

The aging management review results for these component types are indicated in Table 3.3.2-26, Auxiliary Systems - Drains - Gaseous - Aging Management Evaluation.

2.3.3.27 Gaseous Waste Disposal

System Description

The gaseous waste disposal system is designed to maintain effluent radioactivity levels as low as practicable and below the limits of applicable regulations. The system is common to both units and is sized to treat the radioactive gases released during simultaneous operation of both units. Fission product gases and uncondensed radioactive vapors are held for decay, filtered, and diluted with ventilation air until they may be safely released through one of the two vent stacks on top of the Unit 1 containment.

The system contains components that have been classified as safety-related for conservatism, but do not perform a 10 CFR 54.4(a)(1) function. UFSAR 11.3.2 states that the largest accidental radioactivity release would be caused by rupturing of the gaseous waste decay tanks. That event is analyzed in UFSAR section 15.3.5, which concludes that whole body and thyroid doses at the exclusion boundary would be well below the guidelines of 10 CFR 100.

System Evaluation Boundary

The evaluation boundary for the gaseous waste disposal system components subject to aging management review includes only the restricting orifice, instrument piping and valves that support operation of the environmentally qualified process ventilation flow instrumentation. Integrity of the discharge flowpath or other system components is not needed to support the system EQ function and the system does not perform other 10 CFR 54.4 functions.

System Intended Functions

The gaseous waste disposal system is relied upon for compliance with regulations for Environmental Qualification (10 CFR 50.49). Therefore, the gaseous waste disposal system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the gaseous waste disposal system can be found in the UFSAR, Sections 11.3 and 15.3.5.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the gaseous waste disposal system are listed below:

11715-SLRM-097B Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-27, Gaseous Waste Disposal.

The aging management review results for these component types are indicated in Table 3.3.2-27, Auxiliary Systems - Gaseous Waste Disposal - Aging Management Evaluation.

2.3.3.28 Liquid & Solid Waste (Radioactive)

System Description

The liquid and solid waste system is common to both units and is designed to process potentially radioactive liquid and solid wastes produced by the operation of the plant.

System Evaluation Boundary

The evaluation boundary for the liquid and solid waste system components subject to aging management review includes the safety-related evaporator distillate condenser and blowdown coolers that provide pressure boundary integrity for the component cooling system; the nonsafety-related evaporator distillate cooler that provides pressure boundary integrity for the component cooling system; and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components.

System Intended Functions

The liquid and solid waste system performs the following safety-related functions: The system provides a safety-related pressure boundary for the component cooling system, and provides safety-related, non-EQ instrumentation. Therefore, the liquid and solid waste system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The liquid and solid waste system contains nonsafety-related components that provide pressure boundary integrity for safety-related portions of the component cooling system, and contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the liquid and solid waste system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for pressure boundary integrity, spatial interaction, and structural integrity.

UFSAR References

Additional details of the liquid & solid waste (radioactive) system can be found in the UFSAR, Sections 11.2 and 11.5.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the liquid & solid waste (radioactive) system are listed below:

11715-SLRM-087A Sh. 1

11715-SLRM-087A Sh. 2

11715-SLRM-087A Sh. 3

11715-SLRM-087B Sh. 1

11715-SLRM-087B Sh. 2

11715-SLRM-087C Sh. 1

11715-SLRM-087C Sh. 3

11715-SLRM-087C Sh. 4

11715-SLRM-087E Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-28, Liquid & Solid Waste (Radioactive).

The aging management review results for these component types are indicated in Table 3.3.2-28, Auxiliary Systems - Liquid & Solid Waste (Radioactive) - Aging Management Evaluation.

2.3.3.29 Oil Separation

System Description

During normal operating conditions, the oil separation system collects the drainage from the turbine building sumps and the spilled oil pit, separates this discharge into its three component parts (oil, water, and sludge), and directs the output fluids to the appropriate locations for disposal.

System Evaluation Boundary

The evaluation boundary for the oil separation system components subject to aging management review includes the nonsafety-related components that retain water or oil in buildings containing safety-related components.

System Intended Functions

The oil separation system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the oil separation system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

UFSAR References

None

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the oil separation system are listed below:

11715-SLRB-144D Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-29, Oil Separation.

The aging management review results for these component types are indicated in Table 3.3.2-29, Auxiliary Systems - Oil Separation - Aging Management Evaluation.

2.3.3.30 Radioactive Waste

System Description

The radioactive waste system receives radioactive spent resin from various primary ion exchangers and processes the resins to shipping containers for disposal. The system is called the spent resin system in the UFSAR.

System Evaluation Boundary

The evaluation boundary for the radioactive waste system components subject to aging management review includes the safety-related piping associated with chemical and volume control system demineralizer resin flush; and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components.

System Intended Functions

The radioactive waste system performs the following safety-related function: The system provides a safety-related pressure boundary for the chemical and volume control system. Therefore, the radioactive waste system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The radioactive waste system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, radioactive waste system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

UFSAR References

Additional details of the radioactive waste system can be found in the UFSAR, Sections 11.5.2.1 and 11.5.3.3.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the radioactive waste system are listed below:

11715-SLRM-086C Sh. 3

11715-SLRM-087D Sh. 1

11715-SLRM-087D Sh. 2

11715-SLRM-087D Sh. 3

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-30, Radioactive Waste.

The aging management review results for these component types are indicated in Table 3.3.2-30, Auxiliary Systems - Radioactive Waste - Aging Management Evaluation.

2.3.3.31 Sanitary Sewage

System Description

The sanitary sewage system collects and processes effluent from kitchen, rest room, shower, and drinking fountain plumbing fixtures.

System Evaluation Boundary

The evaluation boundary for the sanitary sewage system components subject to aging management review includes the nonsafety-related components that retain water in buildings containing safety-related components.

System Intended Functions

The sanitary sewage system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the sanitary sewage system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

UFSAR References

None

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the sanitary sewage system are listed below:

11715-SLRB-202A Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-31, Sanitary Sewage.

The aging management review results for these component types are indicated in Table 3.3.2-31, Auxiliary Systems - Sanitary Sewage - Aging Management Evaluation.

2.3.3.32 Vents - Gaseous

System Description

The vents - gaseous system collects potentially radioactive gases vented from various plant systems and discharges the gases to the gaseous waste disposal system. The UFSAR describes the vents - gaseous system as a subsystem of the vent and drain system.

System Evaluation Boundary

The evaluation boundary for the vents - gaseous system components subject to aging management review includes the safety-related piping from the drains - gaseous system primary drain transfer coolers and tanks, and from the pressurizer relief tanks within the Containments and through the containment penetrations; and nonsafety-related components that provide support to directly-connected safety-related components, or that retain steam (from the connection to the boron recovery stripper vents) in buildings containing safety-related components.

System Intended Functions

The vents - gaseous system performs the following safety-related functions: The system provides containment isolation. Therefore, the vents - gaseous system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The vents - gaseous system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the vents - gaseous system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The vents - gaseous system is relied upon for compliance with regulations for Environmental Qualification (10 CFR 50.49). Therefore, the vents - gaseous system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the vents - gaseous system can be found in the UFSAR, Section 9.3.3 and Table 6.2-37.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the vents - gaseous system are listed below:

11715-SLRM-090C Sh. 1

12050-SLRM-090A Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-32, Vents - Gaseous.

The aging management review results for these component types are indicated in Table 3.3.2-32, Auxiliary Systems - Vents - Gaseous - Aging Management Evaluation.

2.3.3.33 Containment Vacuum

System Description

The containment vacuum system establishes and maintains the sub-atmospheric pressure of the Containment in support of plant operation. The containment vacuum system also provides a flowpath, via the containment penetration piping, to the post-accident hydrogen removal system.

System Evaluation Boundary

The evaluation boundary for the containment vacuum system components subject to aging management review includes the safety-related containment isolation components, and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components, including the vacuum pump package skids.

System Intended Functions

The containment vacuum system performs the following safety-related functions: The system provides containment isolation, provides a flowpath to the post-accident hydrogen recombiners, and provides non-EQ safety-related instrumentation. Therefore, the containment vacuum system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The containment vacuum system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the containment vacuum system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The containment vacuum system is relied upon for compliance with regulations for Environmental Qualification (10 CFR 50.49). Therefore, the containment vacuum system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the containment vacuum system can be found in the UFSAR, Section 6.2.6 and Table 6.2-37.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the containment vacuum system are listed below:

11715-SLRM-072B Sh. 1

11715-SLRM-092A Sh. 2

12050-SLRM-092A Sh. 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-33, Containment Vacuum.

The aging management review results for these component types are indicated in Table 3.3.2-33, Auxiliary Systems - Containment Vacuum - Aging Management Evaluation.

2.3.3.34 Chilled Water

System Description

The chilled water system is comprised of two separate systems: the chilled water system and the main control room and emergency switchgear room air-conditioning chilled water system.

The chilled water system provides chilled water to remove heat from various plant loads including the containment air recirculation coolers and refueling water storage tank coolers. The service water system can be aligned to supply the chilled water system in the event that the mechanical chillers are unavailable. The main control room and emergency switchgear room air-conditioning chilled water system provides chilled water to remove heat from the control room envelope.

System Evaluation Boundary

The evaluation boundary for the chilled water system components subject to aging management review includes the safety-related closed-loop systems providing chilled water for the control and relay rooms cooling coils (the safety-related chiller units are within the heating and ventilation system), the safety-related cooling water piping to/from the containment recirculation air cooling coils, and nonsafety-related fluid-retaining components within buildings that house safety-related equipment. These nonsafety-related components include flash tanks and condenser units, pumps, mechanical chiller components including pumps and a surge tank, and the associated flowpath piping components and valves. Additionally, the refueling water storage tank coolers are nonsafety-related base-mounted components that provide support to safety-related quench spray piping components in the yard, and are subject to aging management review.

System Intended Functions

The chilled water system performs the following safety-related functions: The chilled water system provides chilled water to the control and relay room cooling coils in the heating and ventilation system, and provides low-temperature cooling water to the containment recirculation air cooling coils. Therefore, the chilled water system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The chilled water system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the chilled water system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

UFSAR References

Additional details of the chilled water system can be found in the UFSAR, Sections 9.2.2 and 9.4.1, and Table 9.2-6.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the chilled water system are listed below:

11715-SLRB-040C Sh. 1

11715-SLRB-040C Sh. 2

11715-SLRB-040C Sh. 3

11715-SLRM-079D Sh. 1

11715-SLRM-079D Sh. 2

11715-SLRM-079D Sh. 3

11715-SLRM-079D Sh. 4

11715-SLRM-079D Sh. 5

12050-SLRM-079B Sh. 1

12050-SLRM-079B Sh. 2

12050-SLRM-079B Sh. 3

12050-SLRM-079D Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-34, Chilled Water.

The aging management review results for these component types are indicated in Table 3.3.2-34, Auxiliary Systems - Chilled Water - Aging Management Evaluation.

2.3.3.35 Heating & Ventilation

System Description

The heating and ventilation system is comprised of several ventilation subsystems with the general function to provide space and equipment cooling. Certain subsystems also provide radiological controls.

The following heating and ventilation subsystems are within the scope of subsequent license renewal:

Auxiliary Ventilation

The auxiliary ventilation subsystem is comprised of fresh air supply and exhaust ventilation for the Auxiliary Building, Fuel Building, Decontamination Building and Safeguards Building, and a common filtration unit. The auxiliary ventilation subsystem also includes the exhaust ventilation filters, fans, dampers, and ductwork for the engineered safety features equipment areas.

Containment Ventilation

The containment ventilation subsystem consists of containment air recirculation, control rod drive mechanism ventilation, and containment purge ventilation.

The containment air recirculation ventilation provides containment heat removal during normal and shutdown operations.

The control rod drive mechanism ventilation cools the ventilation air drawn from the control rod drive mechanism area of the reactor vessel head in order to remove heat generated in the head region.

The containment purge ventilation provides for containment atmosphere air changes for radiological control and personnel habitability during plant shutdown conditions.

Main Control Room and Emergency Switchgear Room Ventilation

The main control room and emergency switchgear room ventilation subsystem is comprised of air-conditioning ventilation components and main control room envelope pressurization components.

The air-conditioning system consists of supply and exhaust ventilation, and a recirculation system. The supply and exhaust system is secured in an emergency in order to isolate the main control room envelope. The recirculation air-conditioning system, including water chillers and associated equipment, air handling units, dampers, and ductwork, provides cooling during normal and emergency conditions.

The pressurization of the main control room envelope is required for postulated accidents involving radioactive release in order to limit the dose to control room personnel. The main control room and emergency switchgear emergency ventilation system consists of fans, filters, dampers, and ductwork.

Other Ventilation Subsystems

There are various other ventilation subsystems installed at the plant:

Ventilation components are installed to provide cooling for critical areas of the Auxiliary Building and the Fuel Building in the event that a severe fire disables the normal ventilation system.

The control rod drive room and cable vault ventilation includes emergency supply ventilation fans and ductwork that provide cooling to safety-related motor control centers if normal ventilation is lost.

Heating Steam Subsystem

The heating steam subsystem provides heating steam to unit heaters and air-handling units in various site buildings. It consists of steam distribution piping and valves, steam traps, and condensate receiver tanks and pumps. Heating steam is supplied from the auxiliary steam system.

System Evaluation Boundary

The evaluation boundary for the auxiliary ventilation subsystem components subject to aging management review includes the safety-related fans, dampers, and ducting in the Auxiliary Building supply and exhaust; the exhaust filter banks; the safety-related dampers and ducting between the Fuel Building and the exhaust filter banks, and between the Decontamination Building and the exhaust filter banks; and directly-connected nonsafety-related ducting and dampers.

The evaluation boundary for the containment ventilation subsystem components subject to aging management review includes the safety-related containment and control rod drive mechanism cooling coils; the safety-related containment isolation components; and the containment purge supply and exhaust ducting and components inside containment and in the flowpath going to vent stack B. The containment iodine removal fans and filters, and the dome recirculation fans, are nonsafety-related and not credited in regulated events, and are not in-scope.

The evaluation boundary for the main control room and emergency switchgear room ventilation subsystem components subject to aging management review includes the safety-related chillers and air-handling units for the control room and relay room, and the safety-related components in the emergency supply air subsystem for the control room and relay room. The bottled, compressed breathing air system, provided to limit in-leakage when outside air is contaminated, is not credited in accident analyses or regulated events, and is not in-scope.

The evaluation boundary for the other heating and ventilation subsystem components subject to aging management review includes the safety-related components in the safeguards area supply and exhaust, the Service Water Pump House, the Auxiliary Feedwater Pump House, and the Service Building battery and chiller rooms.

The evaluation boundary for the heating steam subsystem components subject to aging management review includes nonsafety-related components, including unit heaters and condensate receiver tanks and pumps, that retain steam or water in buildings containing safety-related components.

System Intended Functions

The heating and ventilation system performs the following safety-related functions: The system ventilates equipment areas and routes potentially contaminated air through charcoal filters prior to discharge to the environment, provides containment isolation, and provides non-EQ safety-related instrumentation. Therefore, the heating and ventilation system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The heating and ventilation system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the heating and ventilation system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The heating and ventilation system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), and Station Blackout (10 CFR 50.63). Therefore, the heating and ventilation system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the heating & ventilation system can be found in the UFSAR, Section 9.4 and Table 6.2-37.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the heating & ventilation system are listed below:

11715-SLRB-006A Sh. 1

11715-SLRB-006A Sh. 2

11715-SLRB-006A Sh. 3

11715-SLRB-040E Sh. 1

11715-SLRB-040E Sh. 2

11715-SLRB-040E Sh. 3

11715-SLRB-34A Sh. 1

11715-SLRB-34B Sh. 1

11715-SLRB-34C Sh. 1

11715-SLRB-34D Sh. 1

11715-SLRB-34E Sh. 1

11715-SLRB-44C Sh. 1

11715-SLRB-44E Sh. 1

11715-SLRB-44F Sh. 1

12050-SLRB-34A Sh. 1

12050-SLRB-34B Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-35, Heating & Ventilation.

The aging management review results for these component types are indicated in Table 3.3.2-35, Auxiliary Systems - Heating & Ventilation - Aging Management Evaluation.

2.3.3.36 High Radiation Sampling

System Description

The high radiation sampling system provides the capability to obtain grab samples from various systems and plant areas that can be used to provide indications of post-accident plant conditions. Sample cooling is provided by the component cooling system. The system is no longer required for post-accident sampling and has been removed from the North Anna Technical Specifications but is maintained to provide contingency sampling measures.

System Evaluation Boundary

The evaluation boundary for the high radiation sampling system components subject to aging management review includes the safety-related piping components connected to the component cooling system, and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components. System components within the liquid and chemical analysis sample panels do not have a leakage boundary function and are not subject to aging management review because the sample panels are designed to contain potential leakage for internal components. The sample panels are evaluated as structural components.

System Intended Functions

The high radiation sampling system performs the following safety-related functions: The system provides a safety-related pressure boundary for the component cooling system. Therefore, the high radiation sampling system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The high radiation sampling system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the high radiation sampling system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

UFSAR References

Additional details of the high radiation sampling system can be found in the UFSAR, Section 9.3.2.2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the high radiation sampling system are listed below:

11715-SLRM-090C Sh. 3

11715-SLRM-108A Sh. 1

11715-SLRM-108B Sh. 1

11715-SLRM-108C Sh. 1

11715-SLRM-108E Sh. 1

12050-SLRM-090A Sh. 3

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-36, High Radiation Sampling.

The aging management review results for these component types are indicated in Table 3.3.2-36, Auxiliary Systems - High Radiation Sampling - Aging Management Evaluation.

2.3.3.37 Post-Accident Hydrogen Removal

System Description

The post-accident hydrogen removal system provides the capability to monitor and control the post-accident containment atmosphere hydrogen concentration. The system is comprised of hydrogen recombiner units, hydrogen analyzers, and associated components. The UFSAR refers to the system as the containment atmosphere cleanup system.

System Evaluation Boundary

The evaluation boundary for the post-accident hydrogen removal system components subject to aging management review includes the safety-related containment piping penetrations and flowpaths to hydrogen analyzers and purge blowers and to, but not including the hydrogen recombiners; and nonsafety-related components that provide support to directly-connected safety-related components. The hydrogen recombiners and purge blowers are not credited in design basis or accident analysis. The purge blowers are base-mounted components that provide support to directly connected safety-related piping. The hydrogen recombiners are not within-scope. Integrity of the flowpaths to the gaseous waste system process vent are not required to support safety-related functions, and those flowpaths are not within-scope.

System Intended Functions

The post-accident hydrogen removal system performs the following safety-related functions: The system monitors containment hydrogen concentration and provides containment isolation. Therefore, the post-accident hydrogen removal system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The post-accident hydrogen removal system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the post-accident hydrogen removal system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for structural integrity.

The post-accident hydrogen removal system is relied upon for compliance with regulations for Environmental Qualification (10 CFR 50.49). Therefore, the post-accident hydrogen removal system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the post-accident hydrogen removal system can be found in the UFSAR, Section 6.2.5.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the post-accident hydrogen removal system are listed below:

11715-SLRM-106A Sh. 1

11715-SLRM-106A Sh. 2

11715-SLRM-106A Sh. 3

11715-SLRM-106A Sh. 4

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-37, Post-Accident Hydrogen Removal.

The aging management review results for these component types are indicated in Table 3.3.2-37, Auxiliary Systems - Post-Accident Hydrogen Removal - Aging Management Evaluation.

2.3.3.38 Radiation Monitoring

System Description

The radiation monitoring system provides indication of radiation conditions in various plant areas and within potentially radioactive plant systems.

System Evaluation Boundary

The evaluation boundary for the radiation monitoring system components subject to aging management review includes the safety-related containment penetration piping components associated with the containment air particulate and gaseous radiation monitors, and nonsafety-related components that provide support to directly-connected safety-related components. The system includes both area and process monitor components that are active and not subject to aging management review. Fluid pressure or leakage boundaries associated with process radiation monitors are addressed with the systems which they monitor.

System Intended Functions

The radiation monitoring system performs the following safety-related functions: The system provides containment isolation. Therefore, the radiation monitoring system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The radiation monitoring system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the radiation monitoring system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for structural integrity.

The radiation monitoring system is relied upon for compliance with regulations for Environmental Qualification (10 CFR 50.49). Therefore, the radiation monitoring system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the radiation monitoring system can be found in the UFSAR, Section 11.4 and Table 6.2-37.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the radiation monitoring system are listed below:

11715-SLRM-082N Sh. 3

12050-SLRM-082B Sh. 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-38, Radiation Monitoring.

The aging management review results for these component types are indicated in Table 3.3.2-38, Auxiliary Systems - Radiation Monitoring - Aging Management Evaluation.

2.3.3.39 Alternate AC

System Description

The alternate AC system, installed in response to 10 CFR 50.63, provides AC power to one emergency electrical bus on the selected unit during a Station Blackout (SBO) event. The alternate AC system consists of a diesel generator and the associated fuel oil, starting air, lubricating oil, cooling water, intake and exhaust support systems.

System Evaluation Boundary

The evaluation boundary for the alternate AC system components subject to aging management review includes the fuel oil day tank and the flowpath through transfer pumps and filters to the fuel injector headers and the return flowpath through the fuel oil cooler to the day tank; the starting air flowpath from the compressor supply discharge check valve through the start air receiver and outlet piping to the diesel air start motors; the cooling water expansion tank, radiators, pumps, oil coolers and associated piping components; the intake air filter housings and supply to the diesel skid components and the exhaust subsystem piping from the discharge expansion joints through the silencer to atmosphere; the lubricating oil pumps, heat exchangers and piping components external to the engine. The engine, its integral components, and the electrical generator are active components and are not subject to aging management review. Support components including the engine sump, turbocharger and aftercooler, and fuel injectors are part of the active engine assembly, and are not subject to aging management review. Because the air start receiver contains compressed air required to start the engines, the start air compressors and dryer are not within-scope, not subject to aging management review.

System Intended Functions

The alternate AC system is relied upon for compliance with regulations for Station Blackout (10 CFR 50.63). Therefore, the alternate AC system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the alternate ac system can be found in the UFSAR, Sections 8.1.2 and 9.5.11.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the alternate ac system are listed below:

11715-SLRM-113A Sh. 1

11715-SLRM-113B Sh. 1

11715-SLRM-113C Sh. 1

11715-SLRM-113D Sh. 1

11715-SLRM-113E Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-39, Alternate AC.

The aging management review results for these component types are indicated in Table 3.3.2-39, Auxiliary Systems - Alternate AC - Aging Management Evaluation.

2.3.3.40 Emergency Diesel Generator System

System Description

The emergency diesel generators are diesel engine-driven electrical generators that provide a backup source of electrical power to the emergency electrical buses in the event that the normal supplies are unavailable. The system consists of two diesel generators at each unit and associated fuel oil, starting air, lubricating oil, cooling water, intake and exhaust support subsystems.

System Evaluation Boundary

The evaluation boundary for the emergency diesel generator system components that are subject to aging management review includes the safety-related fuel oil components from the underground fuel oil storage tanks, through underground piping, the fuel oil pumps, fuel oil tanks and associated piping to the diesel fuel injector headers; the starting air subsystem components from the start air tank supply check valves through the air receivers to the engine; the lubricating oil pumps, heat exchangers and piping components that are not integral to the engine; the cooling water expansion and drain tanks, pumps, heat exchangers (excluding the turbocharger aftercoolers and scavenging air coolers) and associated piping components; the exhaust piping from the engine outlet expansion joint to its discharge; as well as nonsafety-related components that provide leakage boundary or structural integrity. The engine, its integral components and the electrical generator are active components and are not subject to aging management review. The fuel injector headers and injectors; start air control valve, air start distributor and associated air start distribution to the cylinders; lubricating oil pan (sump) and cooling fan right angle gearbox; and turbochargers, blowers and associated intake aftercoolers/ air coolers are integral to the active engine assembly and are not subject to aging management review. Because the air start receivers contain compressed air required to start the engines, the start air compressors and dryers are not within-scope, not subject to aging management review.

System Intended Functions

The emergency diesel generator system performs the following safety-related functions: The emergency diesel generator system provides a reliable source of emergency power for safety-related loads and to establish and maintain safe shutdown, and contains non-EQ safety-related instrumentation. Therefore, the emergency diesel generator system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The emergency diesel generator system contains nonsafety-related starting air components whose integrity retains stored starting air, and contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the emergency diesel generator system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for pressure boundary integrity, spatial interaction, and structural integrity.

The emergency diesel generator system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the emergency diesel generator system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the emergency diesel generator system can be found in the UFSAR, Sections 8.3.1.1.1, 8.3.1.1.2.1, 9.5.4, 9.5.5, 9.5.6, 9.5.7, and 9.5.8.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the emergency diesel generator system are listed below:

11715-SLRB-035A Sh. 1

11715-SLRB-035A Sh. 2

11715-SLRB-035C Sh. 1

11715-SLRB-035C Sh. 2

11715-SLRB-035C Sh. 3

11715-SLRB-035C Sh. 4

11715-SLRM-107A Sh. 1

11715-SLRM-107A Sh. 2

11715-SLRM-107A Sh. 3

11715-SLRM-107A Sh. 4

11715-SLRM-107B Sh. 1

11715-SLRM-107B Sh. 2

11715-SLRM-107C Sh. 1

11715-SLRM-107C Sh. 2

11715-SLRM-107D Sh. 1

11715-SLRM-107D Sh. 2

12050-SLRM-107A Sh. 1

12050-SLRM-107A Sh. 2

12050-SLRM-107A Sh. 3

12050-SLRM-107A Sh. 4

12050-SLRM-107B Sh. 1

12050-SLRM-107B Sh. 2

12050-SLRM-107C Sh. 1

12050-SLRM-107C Sh. 2

12050-SLRM-107D Sh. 1

12050-SLRM-107D Sh. 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-40, Emergency Diesel Generator System.

The aging management review results for these component types are indicated in Table 3.3.2-40, Auxiliary Systems - Emergency Diesel Generator System - Aging Management Evaluation.

2.3.3.41 Security

System Description

The security system provides the physical security features of the plant. The portion of the system within the scope of license renewal consists of the back-up electrical diesel generator, cabling, and yard lighting that support fire protection requirements.

System Evaluation Boundary

The evaluation boundary for the security system components subject to aging management review includes the security diesel generator underground fuel oil tank, the fuel oil transfer pump and associated piping components to and including the fuel oil day tank; the silencer and exhaust discharge piping; and the cooling fan discharge ductwork. The remainder of the diesel engine, generator and support components are skid-mounted components that are part of the active assembly, and are not subject to aging management review. The underground fuel oil piping is a double-walled flexible polymer pipe, in which the outer pipe is not required by the manufacturer. The outer pipe does not perform a pressure boundary function and is not subject to aging management review.

System Intended Functions

The security system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the security system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the security system can be found in the UFSAR, Section 9.5.3.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the security system.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-41, Security.

The aging management review results for these component types are indicated in Table 3.3.2-41, Auxiliary Systems - Security - Aging Management Evaluation.

2.3.3.42 Fire Protection

System Description

The fire protection system provides for detection and suppression of fires such that plant equipment damage is minimized and safe shutdown of the plant can be achieved. The fire protection system also provides a back-up source of make-up or cooling water to various plant systems.

The fire protection system is comprised of fire and smoke detection components, water-based fire suppression components (including water tanks (i.e., hydropneumatic tank and retarding chambers), fire pumps, distribution piping, valves, hose stations, hydrants, and sprinkler systems), and gas-based fire suppression components (including carbon dioxide and Halon distribution equipment). The sources of water for the water-based fire suppression system are the circulating water Intake Structure (motor-driven pump), the Service Water Reservoir (diesel-driven pump), and the circulating water pump bay (pressure maintenance pump).

Carbon dioxide suppression is provided for the primary cable vault and tunnel, the Service Building cable vault and tunnel, normal switchgear rooms, cable tray spreading rooms, turbine-generator bearing enclosures, generator exciter enclosures, and emergency diesel generator rooms.

Halon suppression is provided for emergency switchgear and relay rooms; the underfloor areas of the main control rooms, the monitor control room (Security Building), and the security control center; the control room simulator room (Training Center Building); cable vaults of the security control center; and the computer room of the local emergency operations facility (Training Center Building).

System Evaluation Boundary

The evaluation boundary for the fire protection system components subject to aging management review includes the fire protection system motor-driven and diesel-driven pumps (including the fuel oil supply to the diesel), yard piping, and distribution piping and components associated with all sprinkler, spray and hose station suppression features within the protected area. Diesel-driven fire pump engine components within the skid boundaries are part of the active assembly and are not subject to aging management review. The evaluation boundary also includes fire damper assemblies installed in ventilation system ducts and fire barrier penetrations.

All of the carbon dioxide suppression systems, along with the Halon suppression systems in the emergency switchgear and relay rooms and control room, are subject to aging management review. Halon suppression systems in the Security Building and the Training Center Building are not within the scope of subsequent license renewal.

Tank foundations and structural fire barriers such as fire doors, fire-retardant coatings, fire seals, and fire barrier penetration sleeves are evaluated as miscellaneous structural commodities.

The reactor coolant pump motor oil collection system components are evaluated in the reactor coolant system.

System Intended Functions

The fire protection system performs the following safety-related functions: The system provides containment isolation. Therefore, the fire protection system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The fire protection system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the fire protection system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The fire protection system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the fire protection system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the fire protection system can be found in the UFSAR, Section 9.5.1 and Table 6.2-37.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the fire protection system are listed below:

11715-SLRB-035A Sh. 1

11715-SLRB-101A Sh. 1

11715-SLRB-101B Sh. 1

11715-SLRB-101E Sh. 1

11715-SLRB-101H Sh. 1

11715-SLRB-102A Sh. 1

11715-SLRB-102B Sh. 1

11715-SLRB-102C Sh. 1

11715-SLRB-103A Sh. 1

11715-SLRB-103A Sh. 2

11715-SLRB-103A Sh. 3

11715-SLRB-103A Sh. 4

11715-SLRB-103D Sh. 1

11715-SLRB-103E Sh. 1

11715-SLRB-103M Sh. 1

11715-SLRB-104A Sh. 1

11715-SLRB-104B Sh. 1

11715-SLRB-104B Sh. 2

11715-SLRB-104C Sh. 1

11715-SLRB-104C Sh. 2

11715-SLRB-104C Sh. 3

11715-SLRB-104C Sh. 4

11715-SLRB-104D Sh. 1

11715-SLRB-104D Sh. 2

11715-SLRB-104E Sh. 1

11715-SLRB-41B Sh. 1

12050-SLRB-104A Sh. 1

12050-SLRB-105A Sh. 1

12050-SLRB-105A Sh. 2

12050-SLRB-105A Sh. 3

12050-SLRB-105A Sh. 4

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-42, Fire Protection.

The aging management review results for these component types are indicated in Table 3.3.2-42, Auxiliary Systems - Fire Protection - Aging Management Evaluation.

2.3.3.43 Containment Access

System Description

The containment access system includes the personnel airlock and equipment hatches. The system uses hydraulic fluid pumps and actuators to operate the containment personnel airlock locking devices. The system normally operates the locking mechanism using electrically driven hydraulic pump/actuator drives, but a hand pump may be used if the electric pumps are unavailable.

System Evaluation Boundary

The evaluation boundary for the containment access system components subject to aging management review includes the safety-related piping and valves associated with airlock pressure equalization and testing that provide containment integrity, and the nonsafety-related oil reservoirs, pump casings, and piping components that retain oil in buildings containing safety-related components. The airlock and equipment hatch are addressed as structural components.

System Intended Functions

The containment access system performs the following safety-related function: The system provides containment isolation. Therefore, the containment access system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The containment access system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the containment access system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

UFSAR References

None

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the containment access system are listed below:

11715-SLRB-100A Sh. 1

12050-SLRB-100A Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-43, Containment Access.

The aging management review results for these component types are indicated in Table 3.3.2-43, Auxiliary Systems - Containment Access - Aging Management Evaluation.

2.3.3.44 Generator Breaker Cooling

System Description

The generator breaker cooling system provides cooling water to the main generator leads and breaker enclosure components, which are located in the Turbine Building. Cooling water is pumped from an expansion tank through the shell-side of the generator leads cooler, through the main generator breaker enclosure components, and back to the pump suction header.

System Evaluation Boundary

The evaluation boundary for the generator breaker cooling system components subject to aging management review includes the flow paths to and from the expansion tank to the generator breaker cooling water pump suction header, through pumps to the generator leads cooler, to the main generator breaker enclosures, and from the enclosures back to the pump suction header. Components within the breaker enclosures are part of the active breaker assembly and not subject to aging management review. The evaluation boundary also includes the water-filled components associated with the generator breaker air compressors.

System Intended Functions

The generator breaker cooling system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the generator breaker cooling system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

UFSAR References

None

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the generator breaker cooling system are listed below:

11715-SLRM-111A Sh. 1

11715-SLRM-111B Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-44, Generator Breaker Cooling.

The aging management review results for these component types are indicated in Table 3.3.2-44, Auxiliary Systems - Generator Breaker Cooling - Aging Management Evaluation.

2.3.3.45 Water Treatment

System Description

The water treatment system produces steam generator quality water for use as condensate makeup by means of filtration, reverse osmosis and demineralization. The flash evaporators in the water treatment system have been abandoned and are no longer used. The system also provides for chemical additions to treated systems, and is used to support wet layup of steam generators.

System Evaluation Boundary

The evaluation boundary for the water treatment system components subject to aging management review includes safety-related piping components attached to the steam generators, safety-related piping components associated with containment penetrations, and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water in buildings containing safety-related components.

System Intended Functions

The water treatment system performs the following safety-related functions: The system provides containment isolation, provides a pressure boundary for the steam generators, and provides non-EQ safety-related instrumentation. Therefore, the water treatment system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The water treatment system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the water treatment system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

UFSAR References

Additional details of the water treatment system can be found in the UFSAR, Sections 9.2.3.2 and 10.4.3.2, and Table 6.2-37.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the water treatment system are listed below:

11715-SLRM-102A Sh. 1

11715-SLRM-102A Sh. 2

11715-SLRM-102B Sh. 1

11715-SLRM-112A Sh. 1

11715-SLRM-84A Sh. 1

11715-SLRM-84B Sh. 1

12050-SLRM-102A Sh. 1

12050-SLRM-102A Sh. 2

12050-SLRM-102B Sh. 1

12050-SLRM-84A Sh. 1

13075-SLRM-102C Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.3-45, Water Treatment.

The aging management review results for these component types are indicated in Table 3.3.2-45, Auxiliary Systems - Water Treatment - Aging Management Evaluation.

Intentionally Blank

Screening Results Tables: Auxiliary Systems

Table 2.3.3-1 Fuel Pit Cooling

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Expansion joint	Pressure Boundary
Heat exchanger (fuel pit - channel cover)	Pressure Boundary
Heat exchanger (fuel pit - channel)	Pressure Boundary
Heat exchanger (fuel pit - shell)	Pressure Boundary
Heat exchanger (fuel pit - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (fuel pit - tubesheet)	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (fuel cask pumpdown)	Leakage Boundary (Spatial)
Pump casing (fuel pit cooling)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-1, Auxiliary Systems - Fuel Pit Cooling - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-2 Refueling Purification

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Demineralizer shell	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Flexible hose	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (purification)	Leakage Boundary (Spatial)
Pump casing (reverse osmosis feed)	Leakage Boundary (Spatial)
Pump casing (skimmer)	Leakage Boundary (Spatial)
Reverse osmosis housing	Leakage Boundary (Spatial)
Sample sink	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-2, Auxiliary Systems - Refueling Purification - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-3 Primary Grade Water

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Flow element	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (primary grade water service)	Leakage Boundary (Spatial)
Pump casing (primary grade water standby)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-3, Auxiliary Systems - Primary Grade Water - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-4 Helium Vacuum Drying

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Fittings (KF piping clamp)	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.3.2-4, Auxiliary Systems - Helium Vacuum Drying - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-5 Fuel Handling

Component Type	Intended Function(s)
Blind flange (fuel transfer tube)	Pressure Boundary
Bolting	Pressure Boundary
Expansion joint	Pressure Boundary
Fuel transfer tube	Pressure Boundary
Fuel transfer tube enclosure	Pressure Boundary
Piping, piping components	Pressure Boundary, Structural Integrity (Attached)
Reactor cavity seal ring	Pressure Boundary
Valve body	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-5, Auxiliary Systems - Fuel Handling - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-6 Materials Handling

Component Type	Intended Function(s)
Bolting	Structural Support
Crane rails and retaining clips, girders, beams, plates	Structural Support
Lifting devices	Structural Support

The aging management review results for these component types are indicated in Table 3.3.2-6, Auxiliary Systems - Materials Handling - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-7 Service Water

Component Type	Intended Function(s)
Annubar	Pressure Boundary
Annubar (not covered by NRC GL 89-13)	Leakage Boundary (Spatial)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Compressor casing	Structural Integrity (Attached)
Expansion joint	Pressure Boundary
Filter housing	Leakage Boundary (Spatial), Structural Integrity (Attached)
Flexible hose	Leakage Boundary (Spatial), Pressure Boundary
Flow element	Pressure Boundary, Restricts Flow
Flow element (not covered by NRC GL 89-13)	Leakage Boundary (Spatial)
Heat exchanger (aftercooler shell)	Structural Integrity (Attached)
Insulation (safety-related heat traced components)	Thermal insulation
Orifice	Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Piping, piping components (not covered by NRC GL 89-13)	Leakage Boundary (Spatial)
Pump casing (auxiliary service water)	Pressure Boundary
Pump casing (chemical addition makeup)	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-7 Service Water

Component Type	Intended Function(s)
Pump casing (chemical addition)	Leakage Boundary (Spatial)
Pump casing (heating and ventilation)	Pressure Boundary
Pump casing (radiation monitoring)	Pressure Boundary
Pump casing (radiation monitoring) (not covered by NRC GL 89-13)	Leakage Boundary (Spatial)
Pump casing (screen wash)	Pressure Boundary
Pump casing (service water sump)	Leakage Boundary (Spatial)
Pump casing (service water)	Pressure Boundary
Pump casing (sump pump)	Leakage Boundary (Spatial)
Pump casing (tie-in vault sump)	Leakage Boundary (Spatial)
Pump casing (transfer drain) (not covered by NRC GL 89-13)	Leakage Boundary (Spatial)
Radiation monitor housing	Pressure Boundary
Radiation monitor housing (not covered by NRC GL 89-13)	Leakage Boundary (Spatial)
Separator	Leakage Boundary (Spatial)
Spray nozzle	Pressure Boundary, Spray Pattern
Strainer body	Pressure Boundary
Strainer body (not covered by NRC GL 89-13)	Leakage Boundary (Spatial)
Strainer element	Filtration
Tank (air receiver)	Pressure Boundary
Tank (chemical mixing chamber)	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-7 Service Water

Component Type	Intended Function(s)
Tank (desiccant dryer)	Structural Integrity (Attached)
Tank (polymer storage)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Valve body (not covered by NRC GL 89-13)	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.3.2-7, Auxiliary Systems - Service Water - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-8 Bearing Cooling

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Expansion joint	Leakage Boundary (Spatial)
Flexible hose	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (bearing cooling chemical addition)	Leakage Boundary (Spatial)
Pump casing (bearing cooling makeup)	Leakage Boundary (Spatial)
Pump casing (bearing cooling mechanical chiller)	Leakage Boundary (Spatial)
Pump casing (bearing cooling water)	Leakage Boundary (Spatial)
Pump casing (central condenser water)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (brominator)	Leakage Boundary (Spatial)
Tank (chemical addition surge)	Leakage Boundary (Spatial)
Tank (chemical addition)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-8, Auxiliary Systems - Bearing Cooling - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-9 Circulating Water

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Expansion joint	Leakage Boundary (Spatial), Pressure Boundary
Heat exchanger (condenser waterbox)	Leakage Boundary (Spatial)
Insulation (safety-related heat traced components)	Thermal insulation
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (Amertap)	Leakage Boundary (Spatial)
Pump casing (screen wash)	Pressure Boundary
Strainer body	Leakage Boundary (Spatial)
Strainer body (cover)	Leakage Boundary (Spatial)
Tank (ball collector cover)	Leakage Boundary (Spatial)
Tank (ball collector)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-9, Auxiliary Systems - Circulating Water - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-10 Vacuum Priming

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Ejector (body)	Leakage Boundary (Spatial)
Ejector (nozzle)	Leakage Boundary (Spatial)
Expansion joint	Leakage Boundary (Spatial), Pressure Boundary
Fan housing (gland steam condenser)	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Flexible hose	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (vacuum priming)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial), Structural Integrity (Attached)
Sight glass (body)	Leakage Boundary (Spatial), Structural Integrity (Attached)
Silencer / separator	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (air separator)	Leakage Boundary (Spatial)
Tank (vacuum priming seal)	Leakage Boundary (Spatial)
Tank (vacuum priming)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

See Table 2.1-1 for definitions of intended functions.

The aging management review results for these component types are indicated in Table 3.3.2-10, Auxiliary Systems - Vacuum Priming - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-11 Domestic Water

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Flexible hose	Leakage Boundary (Spatial)
Piping (eyewash / safety shower assembly)	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (hot water circulating)	Leakage Boundary (Spatial)
Tank (air chamber)	Leakage Boundary (Spatial)
Tank (hot water storage)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)
Valve body (eyewash / safety shower assembly)	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.3.2-11, Auxiliary Systems - Domestic Water - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-12 Component Cooling

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Expansion joint	Pressure Boundary
Flexible hose	Pressure Boundary
Heat exchanger (component cooling - channel)	Pressure Boundary
Heat exchanger (component cooling - shell)	Pressure Boundary
Heat exchanger (component cooling - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (component cooling - tubesheet)	Pressure Boundary
Orifice	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (component cooling)	Pressure Boundary
Radiation monitor housing	Pressure Boundary
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Tank (surge)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-12, Auxiliary Systems - Component Cooling - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-13 Neutron Shield Tank Cooling

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Heat exchanger (neutron shield tank cooler - channel)	Pressure Boundary
Heat exchanger (neutron shield tank cooler - shell)	Pressure Boundary
Heat exchanger (neutron shield tank cooler - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (neutron shield tank cooler - tubesheet)	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (neutron shield tank cooling)	Pressure Boundary
Strainer body	Pressure Boundary
Tank (neutron shield surge)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-13, Auxiliary Systems - Neutron Shield Tank Cooling - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-14 Instrument Air

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Filter housing	Structural Integrity (Attached)
Flexible hose (portable vent rig)	Pressure Boundary
Heat exchanger (compressor inter, after, and oil cooler - shell)	Leakage Boundary (Spatial)
Heat exchanger (instrument air compressor - channel)	Pressure Boundary
Heat exchanger (instrument air compressor - shell)	Pressure Boundary
Heat exchanger (instrument air compressor - tube and tubesheet)	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (compressor cooling skid)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (air accumulator)	Pressure Boundary
Tank (portable air bottle)	Pressure Boundary
Trap body	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-14, Auxiliary Systems - Instrument Air - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-15 Service Air

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Trap body	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-15, Auxiliary Systems - Service Air - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-16 Primary & Secondary Plant Gas Supplies

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Filter housing	Structural Integrity (Attached)
Flexible hose	Pressure Boundary
Orifice	Structural Integrity (Attached)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Tank (nitrogen reserve)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-16, Auxiliary Systems - Primary & Secondary Plant Gas Supplies - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-17 Penetration Electrical

Component Type	Intended Function(s)
Piping, piping components	Pressure Boundary
Valve body	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-17, Auxiliary Systems - Penetration Electrical - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-18 Leakage Monitoring

Component Type	Intended Function(s)
Piping, piping components	Pressure Boundary, Structural Integrity (Attached)
Valve body	Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-18, Auxiliary Systems - Leakage Monitoring - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-19 Chemical & Volume Control

Component Type	Intended Function(s)
Blender	Pressure Boundary
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Demineralizer shell	Pressure Boundary
Filter housing (boric acid)	Pressure Boundary
Filter housing (letdown)	Pressure Boundary
Filter housing (reactor coolant)	Pressure Boundary
Filter housing (seal injection)	Pressure Boundary
Filter housing (seal water return)	Pressure Boundary
Flexible hose	Leakage Boundary (Spatial), Pressure Boundary
Flow element	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Flow element (flange)	Pressure Boundary
Heat exchanger (batch tank panel steam coils)	Leakage Boundary (Spatial)
Heat exchanger (charging pump gear box lubricating oil - channel)	Pressure Boundary
Heat exchanger (charging pump gear box lubricating oil - shell)	Pressure Boundary
Heat exchanger (charging pump gear box lubricating oil - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (charging pump gear box lubricating oil - tubesheet)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-19 Chemical & Volume Control

Component Type	Intended Function(s)
Heat exchanger (charging pump lubricating oil - channel)	Pressure Boundary
Heat exchanger (charging pump lubricating oil - shell)	Pressure Boundary
Heat exchanger (charging pump lubricating oil - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (charging pump lubricating oil - tubesheet)	Pressure Boundary
Heat exchanger (excess letdown - channel)	Pressure Boundary
Heat exchanger (excess letdown - shell)	Pressure Boundary
Heat exchanger (excess letdown - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (excess letdown - tubesheet)	Pressure Boundary
Heat exchanger (nonregenerative - channel)	Pressure Boundary
Heat exchanger (nonregenerative - shell)	Pressure Boundary
Heat exchanger (nonregenerative - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (nonregenerative - tubesheet)	Pressure Boundary
Heat exchanger (regenerative - channel)	Pressure Boundary
Heat exchanger (regenerative - shell)	Pressure Boundary
Heat exchanger (regenerative - tube)	Heat Transfer, Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-19 Chemical & Volume Control

Component Type	Intended Function(s)
Heat exchanger (regenerative - tubesheet)	Pressure Boundary
Heat exchanger (seal water - channel)	Pressure Boundary
Heat exchanger (seal water - shell)	Pressure Boundary
Heat exchanger (seal water - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (seal water - tubesheet)	Pressure Boundary
Insulation (containment penetration)	Thermal insulation
Insulation (safety-related heat traced components)	Thermal insulation
Orifice	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Piping, piping components (Class 1 <NPS 4)	Pressure Boundary
Piping, piping components (Class 1)	Pressure Boundary
Pump casing (boric acid transfer)	Pressure Boundary
Pump casing (charging pump gear drive lubricating oil)	Pressure Boundary
Pump casing (charging pump motor driven lubricating oil)	Pressure Boundary
Pump casing (charging pump shaft driven lubricating oil)	Pressure Boundary
Pump casing (charging)	Pressure Boundary
Pump casing (zinc addition)	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-19 Chemical & Volume Control

Component Type	Intended Function(s)
Sight glass	Pressure Boundary
Sight glass (body)	Pressure Boundary
Strainer body	Pressure Boundary
Strainer element	Filtration
Tank (boric acid batch)	Pressure Boundary
Tank (boric acid)	Pressure Boundary
Tank (charging pump lubricating oil)	Pressure Boundary
Tank (chemical mixing)	Leakage Boundary (Spatial)
Tank (resin fill)	Leakage Boundary (Spatial)
Tank (volume control)	Pressure Boundary
Tank (zinc addition)	Leakage Boundary (Spatial)
Trap body	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Valve body (Class 1)	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-19, Auxiliary Systems - Chemical & Volume Control - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-20 Boron Recovery

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Demineralizer shell (boron cleanup)	Leakage Boundary (Spatial)
Demineralizer shell (cesium removal)	Leakage Boundary (Spatial)
Evaporator shell	Leakage Boundary (Spatial)
Filter housing (boron cleanup)	Leakage Boundary (Spatial)
Filter housing (boron recovery)	Leakage Boundary (Spatial)
Filter housing (evaporator bottoms)	Leakage Boundary (Spatial)
Heat exchanger (evaporator bottoms cooler - channel)	Leakage Boundary (Spatial)
Heat exchanger (evaporator bottoms cooler - shell)	Pressure Boundary
Heat exchanger (evaporator bottoms cooler - tube and tubesheet)	Pressure Boundary
Heat exchanger (evaporator distillate cooler - channel)	Pressure Boundary
Heat exchanger (evaporator distillate cooler - shell)	Pressure Boundary
Heat exchanger (evaporator distillate cooler - tube and tubesheet)	Pressure Boundary
Heat exchanger (evaporator overhead condenser - channel)	Pressure Boundary
Heat exchanger (evaporator overhead condenser - shell)	Pressure Boundary
Heat exchanger (evaporator overhead condenser - tube and tubesheet)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-20 Boron Recovery

Component Type	Intended Function(s)
Heat exchanger (evaporator reboiler - channel cover)	Leakage Boundary (Spatial)
Heat exchanger (evaporator reboiler - channel)	Leakage Boundary (Spatial)
Heat exchanger (evaporator reboiler - shell)	Leakage Boundary (Spatial)
Heat exchanger (sample cooler - outer tube)	Leakage Boundary (Spatial)
Heat exchanger (stripper feed - channel)	Leakage Boundary (Spatial)
Heat exchanger (stripper feed - shell)	Leakage Boundary (Spatial)
Heat exchanger (stripper steam heater - channel cover)	Leakage Boundary (Spatial)
Heat exchanger (stripper steam heater - channel)	Leakage Boundary (Spatial)
Heat exchanger (stripper steam heater - shell)	Leakage Boundary (Spatial)
Heat exchanger (stripper trim cooler - channel)	Pressure Boundary
Heat exchanger (stripper trim cooler - shell)	Pressure Boundary
Heat exchanger (stripper trim cooler - tube and tubesheet)	Pressure Boundary
Heat exchanger (stripper vent chiller - channel)	Leakage Boundary (Spatial)
Heat exchanger (stripper vent chiller - shell)	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-20 Boron Recovery

Component Type	Intended Function(s)
Heat exchanger (stripper vent condenser - channel)	Leakage Boundary (Spatial)
Heat exchanger (stripper vent condenser - shell)	Leakage Boundary (Spatial)
Heater housing (evaporator bottoms cooler preheater)	Pressure Boundary
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (evaporator bottoms cooler circulating)	Pressure Boundary
Pump casing (evaporator bottoms tank circulating)	Leakage Boundary (Spatial)
Pump casing (evaporator bottoms)	Leakage Boundary (Spatial)
Pump casing (evaporator circulating)	Leakage Boundary (Spatial)
Pump casing (evaporator distillate)	Leakage Boundary (Spatial)
Pump casing (stripper circulation)	Leakage Boundary (Spatial)
Pump casing (stripper discharge)	Leakage Boundary (Spatial)
Pump casing (test tank)	Leakage Boundary (Spatial)
Rupture disc	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (distillate accumulator)	Leakage Boundary (Spatial)
Tank (evaporator bottoms)	Leakage Boundary (Spatial)
Tank (gas stripper)	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-20 Boron Recovery

Component Type	Intended Function(s)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-20, Auxiliary Systems - Boron Recovery - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-21 Sampling System

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Demineralizer shell	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Flow indicator	Leakage Boundary (Spatial)
Flow indicator (body)	Leakage Boundary (Spatial)
Heat exchanger (chiller bath)	Leakage Boundary (Spatial)
Heat exchanger (heating bath)	Leakage Boundary (Spatial)
Heat exchanger (sample bath chiller condenser water side)	Leakage Boundary (Spatial)
Heat exchanger (sample bath chiller evaporator water side)	Leakage Boundary (Spatial)
Heat exchanger (sample cooler - outer tube/shell)	Leakage Boundary (Spatial)
Level glass	Leakage Boundary (Spatial)
Level glass (housing)	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Piping, piping components (Class 1)	Pressure Boundary
Pump casing (chiller bath circulating)	Leakage Boundary (Spatial)
Pump casing (collection tank)	Leakage Boundary (Spatial)
Pump casing (flushing)	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-21 Sampling System

Component Type	Intended Function(s)
Pump casing (sample)	Leakage Boundary (Spatial)
Radiation monitor housing	Leakage Boundary (Spatial)
Sample sink	Leakage Boundary (Spatial)
Tank (collection)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary
Valve body (Class 1)	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-21, Auxiliary Systems - Sampling System - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-22 Incore Instrumentation

Component Type	Intended Function(s)
Valve body	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-22, Auxiliary Systems - Incore Instrumentation - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-23 Decontamination

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.3.2-23, Auxiliary Systems - Decontamination - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-24 Drains - Aerated

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Flexible hose	Leakage Boundary (Spatial), Pressure Boundary
Flow totalizer	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (containment mat sump)	Pressure Boundary
Pump casing (sump pump)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (primary vent pot)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-24, Auxiliary Systems - Drains - Aerated - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-25 Drains - Building Services

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Flexible hose	Leakage Boundary (Spatial)
Grating (storm drain)	Filtration
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Piping, piping components (roof drains)	Leakage Boundary (Spatial)
Piping, piping components (storm drain)	Flow Distribution
Pump casing (chiller room sump - case)	Pressure Boundary
Pump casing (chiller room sump - discharge head)	Pressure Boundary
Pump casing (chiller room sump - suction strainer)	Filtration
Pump casing (oil drain collection)	Leakage Boundary (Spatial)
Pump casing (sump pump)	Leakage Boundary (Spatial)
Pump casing (tunnel sump pump)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (oil drain collection)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-25, Auxiliary Systems - Drains - Building Services - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-26 Drains - Gaseous

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Filter housing	Pressure Boundary
Heat exchanger (primary drains transfer - channel)	Pressure Boundary
Heat exchanger (primary drains transfer - shell)	Pressure Boundary
Heat exchanger (primary drains transfer - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (primary drains transfer - tubesheet)	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (primary drain transfer)	Pressure Boundary
Strainer body	Pressure Boundary
Tank (primary drain transfer)	Pressure Boundary
Tank (Unit 2 level column head tank)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-26, Auxiliary Systems - Drains - Gaseous - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-27 Gaseous Waste Disposal

Component Type	Intended Function(s)
Bolting	Pressure Boundary
Orifice	Restricts Flow
Piping, piping components	Pressure Boundary
Valve body	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-27, Auxiliary Systems - Gaseous Waste Disposal - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-28 Liquid & Solid Waste (Radioactive)

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Demineralizer shell	Leakage Boundary (Spatial)
Evaporator shell	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Flow element	Leakage Boundary (Spatial)
Heat exchanger (blowdown - channel)	Pressure Boundary
Heat exchanger (blowdown - shell)	Pressure Boundary
Heat exchanger (blowdown - tube and tubesheet)	Pressure Boundary
Heat exchanger (evaporator bottoms cooler - channel)	Leakage Boundary (Spatial)
Heat exchanger (evaporator bottoms cooler - shell)	Leakage Boundary (Spatial)
Heat exchanger (evaporator distillate - channel)	Leakage Boundary (Spatial)
Heat exchanger (evaporator distillate - shell)	Pressure Boundary
Heat exchanger (evaporator distillate - tube and tubesheet)	Pressure Boundary
Heat exchanger (evaporator distillate condenser - channel)	Pressure Boundary
Heat exchanger (evaporator distillate condenser - shell)	Pressure Boundary
Heat exchanger (evaporator distillate condenser - tube and tubesheet)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-28 Liquid & Solid Waste (Radioactive)

Component Type	Intended Function(s)
Heat exchanger (evaporator reboiler - channel)	Leakage Boundary (Spatial)
Heat exchanger (evaporator reboiler - shell)	Leakage Boundary (Spatial)
Heat exchanger (evaporator sample cooler - outer tube)	Leakage Boundary (Spatial)
Heat exchanger (seal cooling - shell)	Leakage Boundary (Spatial)
Heater housing (bottoms cooler preheater)	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (blowdown pump)	Leakage Boundary (Spatial)
Pump casing (bottoms cooler circulating)	Leakage Boundary (Spatial)
Pump casing (bottoms cooler)	Leakage Boundary (Spatial)
Pump casing (contaminated drain transfer)	Leakage Boundary (Spatial)
Pump casing (drain tank)	Leakage Boundary (Spatial)
Pump casing (evaporator circulating)	Leakage Boundary (Spatial)
Pump casing (evaporator distillate)	Leakage Boundary (Spatial)
Pump casing (evaporator test tank)	Leakage Boundary (Spatial)
Pump casing (resin transfer)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (distillate accumulator)	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-28 Liquid & Solid Waste (Radioactive)

Component Type	Intended Function(s)
Tank (evaporator test)	Leakage Boundary (Spatial)
Tank (laboratory drain sump)	Leakage Boundary (Spatial)
Tank (waste drain)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.3.2-28, Auxiliary Systems - Liquid & Solid Waste (Radioactive) - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-29 Oil Separation

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (waste oil separation)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.3.2-29, Auxiliary Systems - Oil Separation - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-30 Radioactive Waste

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Flow element	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-30, Auxiliary Systems - Radioactive Waste - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-31 Sanitary Sewage

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Flexible hose	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (sewage ejector)	Leakage Boundary (Spatial)
Tank (electric shop sewage waste)	Leakage Boundary (Spatial)
Tank (service and turbine building sewage waste)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.3.2-31, Auxiliary Systems - Sanitary Sewage - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-32 Vents - Gaseous

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-32, Auxiliary Systems - Vents - Gaseous - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-33 Containment Vacuum

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Ejector (containment vacuum - chamber)	Leakage Boundary (Spatial)
Ejector (containment vacuum - diffuser/steam chest)	Leakage Boundary (Spatial)
Ejector (containment vacuum - nozzle)	Leakage Boundary (Spatial)
Heat exchanger (containment vacuum - channel)	Leakage Boundary (Spatial)
Heat exchanger (containment vacuum - shell)	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (containment vacuum)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (moisture separator)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-33, Auxiliary Systems - Containment Vacuum - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-34 Chilled Water

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Compressor (oil reservoir)	Leakage Boundary (Spatial)
Ejector (steam chest and diffuser)	Leakage Boundary (Spatial)
Ejector (steam nozzle)	Leakage Boundary (Spatial)
Expansion joint	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Flexible hose	Leakage Boundary (Spatial), Pressure Boundary
Heat exchanger (air ejector - shell)	Leakage Boundary (Spatial)
Heat exchanger (chilled water condenser - shell)	Leakage Boundary (Spatial)
Heat exchanger (chilled water condenser - waterbox)	Leakage Boundary (Spatial)
Heat exchanger (mechanical chiller condenser - channel)	Leakage Boundary (Spatial)
Heat exchanger (mechanical chiller cooler - channel)	Leakage Boundary (Spatial)
Heat exchanger (mechanical chiller oil cooler - channel)	Leakage Boundary (Spatial)
Heat exchanger (mechanical chiller oil cooler - shell)	Leakage Boundary (Spatial)
Heat exchanger (pumpout condenser - channel)	Leakage Boundary (Spatial)
Heat exchanger (RWST cooler - channel)	Structural Integrity (Attached)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-34 Chilled Water

Component Type	Intended Function(s)
Heat exchanger (RWST cooler - shell)	Structural Integrity (Attached)
Orifice	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (central chilled water)	Leakage Boundary (Spatial)
Pump casing (chilled water circulating)	Leakage Boundary (Spatial)
Pump casing (chilled water condensate)	Leakage Boundary (Spatial)
Pump casing (control & relay room chilled water)	Pressure Boundary
Pump casing (mechanical chilled water circulating)	Leakage Boundary (Spatial)
Pump casing (mechanical chiller lube oil)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial), Pressure Boundary
Sight glass (body)	Leakage Boundary (Spatial), Pressure Boundary
Steam trap	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial), Pressure Boundary
Strainer element	Filtration
Tank (chilled water flash)	Leakage Boundary (Spatial)
Tank (chilled water surge)	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-34 Chilled Water

Component Type	Intended Function(s)
Tank (HV chemical feed)	Leakage Boundary (Spatial), Pressure Boundary
Tank (HV expansion)	Leakage Boundary (Spatial), Pressure Boundary
Tank (oil separator)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-34, Auxiliary Systems - Chilled Water - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-35 Heating & Ventilation

Component Type	Intended Function(s)
Air handling unit (fin)	Heat Transfer
Air handling unit (header)	Pressure Boundary
Air handling unit (housing)	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Air handling unit (tube)	Heat Transfer, Pressure Boundary
Bolting	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Compressor body (control room chiller)	Pressure Boundary
Damper housing	Pressure Boundary, Structural Integrity (Attached)
Ducting	Pressure Boundary, Structural Integrity (Attached)
Expansion joint	Pressure Boundary
Fan housing (Appendix R)	Pressure Boundary
Fan housing (Auxiliary Building exhaust - central)	Pressure Boundary
Fan housing (Auxiliary Building exhaust - general)	Pressure Boundary
Fan housing (auxiliary feed pump room exhaust)	Pressure Boundary
Fan housing (battery room exhaust)	Pressure Boundary
Fan housing (chiller room exhaust)	Pressure Boundary
Fan housing (control room emergency supply)	Pressure Boundary
Fan housing (Intake Structure exhaust)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-35 Heating & Ventilation

Component Type	Intended Function(s)
Fan housing (motor control center)	Pressure Boundary
Fan housing (safeguards area exhaust)	Pressure Boundary
Fan housing (safeguards area)	Pressure Boundary
Fan housing (service water pump house exhaust)	Pressure Boundary
Filter housing (Auxiliary Building exhaust)	Pressure Boundary
Filter housing (containment purge supply vent)	Pressure Boundary
Filter housing (control room emergency supply)	Pressure Boundary
Filter housing (refrigerant)	Pressure Boundary
Filter housing (relay room emergency supply)	Pressure Boundary
Heat exchanger (central area chiller condenser - channel)	Leakage Boundary (Spatial)
Heat exchanger (central area chiller evaporator - shell)	Leakage Boundary (Spatial)
Heat exchanger (containment cooling - fin)	Heat Transfer
Heat exchanger (containment cooling - header)	Pressure Boundary
Heat exchanger (containment cooling - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (control room chiller condenser - channel)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-35 Heating & Ventilation

Component Type	Intended Function(s)
Heat exchanger (control room chiller condenser - shell)	Pressure Boundary
Heat exchanger (control room chiller condenser - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (control room chiller condenser - tubesheet)	Pressure Boundary
Heat exchanger (control room chiller evaporator - channel)	Pressure Boundary
Heat exchanger (control room chiller evaporator - shell)	Pressure Boundary
Heat exchanger (control room chiller evaporator - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (control room chiller evaporator - tubesheet)	Pressure Boundary
Heat exchanger (CRDM cooling - fin)	Heat Transfer
Heat exchanger (CRDM cooling - header)	Pressure Boundary
Heat exchanger (CRDM cooling - tube)	Heat Transfer, Pressure Boundary
Heater (ventilation unit header)	Leakage Boundary (Spatial)
Heating coil (ventilation unit heater)	Leakage Boundary (Spatial)
Moisture separator (control room emergency supply)	Pressure Boundary
Moisture separator (relay room emergency supply)	Pressure Boundary
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-35 Heating & Ventilation

Component Type	Intended Function(s)
Pump casing (condensate return)	Leakage Boundary (Spatial)
Pump casing (condensate)	Leakage Boundary (Spatial)
Rupture plug	Pressure Boundary
Sight glass	Leakage Boundary (Spatial), Pressure Boundary
Sight glass (body)	Leakage Boundary (Spatial), Pressure Boundary
Strainer body	Leakage Boundary (Spatial)
Tank (condensate)	Leakage Boundary (Spatial)
Trap body	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-35, Auxiliary Systems - Heating & Ventilation - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-36 High Radiation Sampling

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Flexible hose	Leakage Boundary (Spatial)
Fume hood	Leakage Boundary (Spatial)
Heat exchanger (sample cooler - shell)	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (containment sump sample)	Leakage Boundary (Spatial)
Pump casing (waste)	Leakage Boundary (Spatial)
Tank (sample flask)	Leakage Boundary (Spatial)
Tank (waste)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-36, Auxiliary Systems - High Radiation Sampling - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-37 Post-Accident Hydrogen Removal

Component Type	Intended Function(s)
Blower housing (containment atmosphere purge)	Structural Integrity (Attached)
Bolting	Pressure Boundary, Structural Integrity (Attached)
Flexible hose	Pressure Boundary
Piping, piping components	Pressure Boundary, Structural Integrity (Attached)
Valve body	Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-37, Auxiliary Systems - Post-Accident Hydrogen Removal - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-38 Radiation Monitoring

Component Type	Intended Function(s)
Bolting	Pressure Boundary, Structural Integrity (Attached)
Piping, piping components	Pressure Boundary, Structural Integrity (Attached)
Valve body	Pressure Boundary, Structural Integrity (Attached)

The aging management review results for these component types are indicated in Table 3.3.2-38, Auxiliary Systems - Radiation Monitoring - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-39 Alternate AC

Component Type	Intended Function(s)
Bolting	Pressure Boundary
Expansion joint	Pressure Boundary
Filter element (vent screen)	Filtration
Filter housing	Pressure Boundary
Filter housing (head)	Pressure Boundary
Flexible hose	Pressure Boundary
Heat exchanger (cooling water radiators - fin)	Heat Transfer
Heat exchanger (cooling water radiators - header)	Pressure Boundary
Heat exchanger (cooling water radiators - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (fuel oil radiator - fin)	Heat Transfer
Heat exchanger (fuel oil radiator - header)	Pressure Boundary
Heat exchanger (fuel oil radiator - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (lube oil - channel)	Pressure Boundary
Heat exchanger (lube oil - shell)	Pressure Boundary
Heat exchanger (lube oil - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (lube oil - tubesheet)	Pressure Boundary
Heater housing (jacket water)	Pressure Boundary
Heater housing (lube oil)	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-39 Alternate AC

Component Type	Intended Function(s)
Lubricator body	Pressure Boundary
Orifice	Pressure Boundary, Restricts Flow
Piping, piping components	Pressure Boundary
Pump casing (fuel transfer)	Pressure Boundary
Pump casing (jacket water)	Pressure Boundary
Pump casing (lube oil)	Pressure Boundary
Sight glass	Pressure Boundary
Sight glass (body)	Pressure Boundary
Silencer	Pressure Boundary
Tank (cooling water expansion)	Pressure Boundary
Tank (fuel oil)	Pressure Boundary
Tank (fuel rack shutoff air)	Pressure Boundary
Tank (start air receiver)	Pressure Boundary
Valve body	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-39, Auxiliary Systems - Alternate AC - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-40 Emergency Diesel Generator System

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Expansion joint	Pressure Boundary
Filter housing	Leakage Boundary (Spatial), Pressure Boundary
Flame arrestor	Pressure Boundary
Flexible hose	Leakage Boundary (Spatial), Pressure Boundary
Heat exchanger (lubricating oil - channel)	Pressure Boundary
Heat exchanger (lubricating oil - shell)	Pressure Boundary
Heat exchanger (lubricating oil - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (lubricating oil - tubesheet)	Pressure Boundary
Heat exchanger (radiator - header)	Pressure Boundary
Heat exchanger (radiator - tube)	Heat Transfer, Pressure Boundary
Heater housing	Pressure Boundary
Level gage	Pressure Boundary
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Pump casing (circulation)	Pressure Boundary
Pump casing (fuel oil transfer)	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-40 Emergency Diesel Generator System

Component Type	Intended Function(s)
Pump casing (fuel oil)	Pressure Boundary
Pump casing (jacket water)	Pressure Boundary
Pump casing (lubricating oil)	Pressure Boundary
Pump casing (pre-lube)	Pressure Boundary
Rupture disc	Pressure Boundary
Sight glass	Pressure Boundary
Sight glass (body)	Pressure Boundary
Strainer body	Leakage Boundary (Spatial), Pressure Boundary
Strainer element	Filtration
Tank (coolant drain)	Pressure Boundary
Tank (coolant expansion)	Pressure Boundary
Tank (dirty fuel)	Pressure Boundary
Tank (fuel oil - day)	Pressure Boundary
Tank (fuel oil storage)	Pressure Boundary
Tank (start air receiver)	Pressure Boundary
Trap body	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary
Water separator	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.3.2-40, Auxiliary Systems - Emergency Diesel Generator System - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-41 Security

Component Type	Intended Function(s)
Bolting	Pressure Boundary
Damper housing	Pressure Boundary
Duct (cooling air discharge)	Pressure Boundary
Filter housing	Pressure Boundary
Flame arrestor	Fire Barrier
Piping, piping components	Pressure Boundary
Pump casing	Pressure Boundary
Silencer	Pressure Boundary
Tank (fuel oil - day)	Pressure Boundary
Tank (underground fuel oil storage)	Pressure Boundary
Valve body	Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-41, Auxiliary Systems - Security - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-42 Fire Protection

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Fire damper assembly	Fire Barrier, Pressure Boundary
Fire hydrant	Pressure Boundary
Flame arrestor	Pressure Boundary
Flexible hose	Pressure Boundary
Heat exchanger (carbon dioxide tank cooling coil)	Pressure Boundary
Insulation (heat traced components)	Thermal insulation
Nozzle	Spray Pattern
Odorizer	Pressure Boundary
Orifice	Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (diesel driven fire pump)	Pressure Boundary
Pump casing (motor driven fire pump)	Pressure Boundary
Pump casing (pressure maintenance)	Pressure Boundary
Rupture disc	Pressure Boundary
Sight glass	Pressure Boundary
Sight glass (body)	Pressure Boundary
Sprinkler head	Spray Pattern
Strainer body	Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-42 Fire Protection

Component Type	Intended Function(s)
Strainer element (deluge/alarm check valve)	Filtration
Strainer element (pump suction)	Filtration
Strainer element (turbine building supply header)	Filtration
Tank (17-ton carbon dioxide storage)	Pressure Boundary
Tank (6-ton carbon dioxide storage)	Pressure Boundary
Tank (carbon dioxide cylinder)	Pressure Boundary
Tank (carbon dioxide delay)	Pressure Boundary
Tank (fire pump fuel oil)	Pressure Boundary
Tank (halon cylinder)	Pressure Boundary
Tank (hydropneumatic)	Pressure Boundary
Tank (nitrogen manual release)	Pressure Boundary
Tank (nitrogen)	Pressure Boundary
Tank (retarding chamber)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-42, Auxiliary Systems - Fire Protection - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-43 Containment Access

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Filter housing	Leakage Boundary (Spatial)
Flexible hose	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (hand)	Leakage Boundary (Spatial)
Pump casing (hydraulic - electric)	Leakage Boundary (Spatial)
Tank (oil reservoir)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-43, Auxiliary Systems - Containment Access - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-44 Generator Breaker Cooling

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Flexible hose	Leakage Boundary (Spatial)
Heat exchanger (generator breaker generator leads - channel)	Leakage Boundary (Spatial)
Heat exchanger (generator breaker generator leads - shell)	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (generator breaker cooling water)	Leakage Boundary (Spatial)
Separator	Leakage Boundary (Spatial)
Silencer	Leakage Boundary (Spatial)
Tank (expansion)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.3.2-44, Auxiliary Systems - Generator Breaker Cooling - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-45 Water Treatment

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Demineralizer shell	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Flash evaporator (shell)	Leakage Boundary (Spatial)
Flow element	Leakage Boundary (Spatial)
Heat exchanger (flash evaporator vent condenser - shell and channel)	Leakage Boundary (Spatial)
Heat exchanger (Unit 1 flash evaporator distillate cooler - shell and channel)	Leakage Boundary (Spatial)
Heat exchanger (Unit 2 flash evaporator distillate cooler - channel)	Leakage Boundary (Spatial)
Heat exchanger (Unit 2 flash evaporator distillate cooler - shell)	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (chemical feed slug)	Leakage Boundary (Spatial)
Pump casing (chemical feed)	Leakage Boundary (Spatial)
Pump casing (chemistry booster pump)	Leakage Boundary (Spatial)
Pump casing (demineralizer sump)	Leakage Boundary (Spatial)
Pump casing (flash evaporator distillate)	Leakage Boundary (Spatial)
Pump casing (flash evaporator makeup)	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.3-45 Water Treatment

Component Type	Intended Function(s)
Pump casing (flash evaporator recirculation)	Leakage Boundary (Spatial)
Pump casing (sand filter backwash)	Leakage Boundary (Spatial)
Pump casing (steam generator transfer)	Leakage Boundary (Spatial)
Pump casing (steam generator wet lay-up recirculation)	Leakage Boundary (Spatial)
Pump casing (Unit 2 vacuum)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (air-water separation)	Leakage Boundary (Spatial)
Tank (chemical addition)	Leakage Boundary (Spatial)
Tank (chemical feed)	Leakage Boundary (Spatial)
Tank (chemistry lab demineralized water storage)	Leakage Boundary (Spatial)
Tank (dilution water head)	Leakage Boundary (Spatial)
Tank (measure)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.3.2-45, Auxiliary Systems - Water Treatment - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

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2.3.4 STEAM AND POWER CONVERSION SYSTEMS

2.3.4.1 Main Steam

System Description

The main steam system transports steam produced in the steam generators to the main turbine for the production of electricity. Additionally, the main steam system provides motive steam to the turbine-driven auxiliary feed pump; removes heat from the reactor coolant system via the ASME Code safety valves, steam generator power-operated relief valves, and/or condenser steam dump valves; and isolates steam flow to the main turbine following a reactor trip or during accident conditions to prevent an excessive cooldown that could have an adverse effect on the reactor.

The gland steam system, a subsystem of the main steam system, prevents air inleakage and steam outleakage along the turbine shaft. The gland steam system reduces high-pressure steam supplied from the main steam manifold to low-pressure steam for supply to the turbine shaft glands.

System Evaluation Boundary

The evaluation boundary for the main steam system components subject to aging management review includes the safety-related steam lines from the steam generators to the main steam isolation valves and to the auxiliary feedwater pump turbine, and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water, steam or oil in buildings containing safety-related components. Thermal insulation on main steam lines within containment penetrations is also subject to aging management review.

System Intended Functions

The main steam system performs the following safety-related functions: The system removes heat from the reactor coolant system; provides overpressure protection for the main steam system; prevents uncontrolled blowdown of more than one steam generator; provides steam to the turbine driven auxiliary feedwater pump; provides containment isolation; and provides non-EQ safety-related instrumentation. Therefore, the main steam system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The main steam system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the main steam system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The main steam system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the main steam system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the main steam system can be found in the UFSAR, Sections 10.2 and 10.3, and Table 6.2-37.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the main steam system are listed below:

11715-SLRM-070A Sh. 1

11715-SLRM-070A Sh. 2

11715-SLRM-070A Sh. 3

11715-SLRM-070A Sh. 4

11715-SLRM-070B Sh. 1

11715-SLRM-070B Sh. 2

11715-SLRM-070B Sh. 3

11715-SLRM-100A Sh. 1

11715-SLRM-100A Sh. 2

11715-SLRM-100A Sh. 3

12050-SLRM-070A Sh. 1

12050-SLRM-070A Sh. 2

12050-SLRM-070A Sh. 3

12050-SLRM-070A Sh. 4

12050-SLRM-070B Sh. 1

12050-SLRM-070B Sh. 2

12050-SLRM-070B Sh. 3

12050-SLRM-100A Sh. 1

12050-SLRM-100A Sh. 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-1, Main Steam.

The aging management review results for these component types are indicated in Table 3.4.2-1, Steam and Power Conversion System - Main Steam - Aging Management Evaluation.

2.3.4.2 Auxiliary Boilers

System Description

The auxiliary boiler system provides steam to the auxiliary steam system when both reactor plant units are shut down. When in use, the auxiliary boiler system can distribute the steam to any of the various auxiliary steam system loads.

During normal auxiliary boiler operation, feedwater enters the boiler though the feedwater nozzle. The cooler feedwater flows down through the downcomers to one of the two mud drums. The water circulation causes warmer water to flow up into the boiler tubes where the water is turned into steam. The steam rises up the boiler tubes to the steam drum. In the steam drum, the steam passes through water separators to remove any entrained water and then flows into the auxiliary steam header.

System Evaluation Boundary

The evaluation boundary for the auxiliary boiler system components subject to aging management review includes nonsafety-related components that retain water, steam or oil in buildings containing safety-related components. These include the auxiliary boilers and steam drums, a deaerator, condensate return pumps, boiler feed pumps, chemical feed tanks, a blowdown tank, and a fuel oil supply system that includes heat exchangers.

System Intended Functions

The auxiliary boiler system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the auxiliary boiler system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

UFSAR References

Additional details of the auxiliary boilers system can be found in the UFSAR, Section 10.4.1.2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the auxiliary boilers system are listed below:

11715-SLRB-035A Sh. 1

11715-SLRM-103A Sh. 1

11715-SLRM-103B Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-2, Auxiliary Boilers.

The aging management review results for these component types are indicated in Table 3.4.2-2, Steam and Power Conversion System - Auxiliary Boilers - Aging Management Evaluation.

2.3.4.3 Extraction Steam

System Description

The extraction steam system provides steam to pre-heat the condensate in the feedwater heaters. During normal operation, the extraction steam system is the source of steam for the auxiliary steam system.

System Evaluation Boundary

The evaluation boundary for the extraction steam system components subject to aging management review includes nonsafety-related components that retain water or steam in buildings containing safety-related components.

There are no passive mechanical components in the extraction steam system whose integrity is relied upon to support safety-related functions.

System Intended Functions

The extraction steam system performs the following safety-related functions: The system provides non-EQ safety-related instrumentation. Therefore, the extraction steam system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The extraction steam system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the extraction steam system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

UFSAR References

Additional details of the extraction steam system can be found in the UFSAR, Section 10.4.1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the extraction steam system are listed below:

11715-SLRM-71A Sh. 1

12050-SLRM-71A Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-3, Extraction Steam.

The aging management review results for these component types are indicated in Table 3.4.2-3, Steam and Power Conversion System - Extraction Steam - Aging Management Evaluation.

2.3.4.4 Auxiliary Steam

System Description

The auxiliary steam system supplies low pressure, saturated steam to various plant systems.

System Evaluation Boundary

The evaluation boundary for the auxiliary steam system components subject to aging management review includes nonsafety-related components that provide a pressure boundary for the main steam system in the event of a station blackout or an Appendix R event, the steam lines from the main steam headers, and nonsafety-related components that retain water or steam in buildings containing safety-related components.

System Intended Functions

The auxiliary steam system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the auxiliary steam system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The auxiliary steam system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, the auxiliary steam system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the auxiliary steam system can be found in the UFSAR, Section 10.4.1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the auxiliary steam system are listed below:

11715-SLRM-072A Sh. 1

11715-SLRM-072A Sh. 2

11715-SLRM-072A Sh. 3

11715-SLRM-072B Sh. 1

11715-SLRM-079D Sh. 2

11715-SLRM-103A Sh. 1

12050-SLRM-072A Sh. 1

12050-SLRM-072A Sh. 2

12050-SLRM-072A Sh. 3

12050-SLRM-079B Sh. 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-4, Auxiliary Steam.

The aging management review results for these component types are indicated in Table 3.4.2-4, Steam and Power Conversion System - Auxiliary Steam - Aging Management Evaluation.

2.3.4.5 Feedwater

System Description

The feedwater system is comprised of main feedwater and auxiliary feedwater. Main feedwater provides treated water to maintain inventory in the steam generators for the production of steam and to provide a heat sink for the reactor coolant system. Main feedwater components provide a flowpath for auxiliary feedwater flow to the steam generator, and provide isolation of main feedwater flow in response to plant transients.

Auxiliary feedwater provides an emergency source of water to the steam generators for reactor heat removal. Auxiliary feedwater provides a heat sink during design basis events, including loss of power conditions. The system consists of three auxiliary feedwater pumps and associated components. The source of water is the emergency condensate storage tank in the condensate system.

System Evaluation Boundary

The evaluation boundary for the feedwater system components subject to aging management review includes the safety-related auxiliary feedwater pumps and related piping and components from the 110,000 gallon condensate storage tanks to main feedwater piping connection downstream from the outboard containment isolation valves. The evaluation boundary also includes auxiliary feedwater pump lubricating oil cooling components; instrument air accumulators and associated components for feedwater flow control valve actuators; and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water, steam or oil in buildings containing safety-related components. Thermal insulation on feedwater lines within containment penetrations is also subject to aging management review.

System Intended Functions

The feedwater system performs the following safety-related functions: The system supplies water to the steam generators during and following design basis events; limits auxiliary feedwater flow to a faulted steam generator; provides containment isolation; and provides non-EQ safety-related instrumentation. Therefore, the feedwater system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The feedwater system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the feedwater system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The feedwater system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the feedwater system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the feedwater system can be found in the UFSAR, Section 10.4.3, and Tables 6.2-37 and 10.4-2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the feedwater system are listed below:

11715-SLRM-074A Sh. 1

11715-SLRM-074A Sh. 2

11715-SLRM-074A Sh. 3

11715-SLRM-074A Sh. 4

11715-SLRM-074B Sh. 1

11715-SLRM-074C Sh. 1

11715-SLRM-078B Sh. 3

11715-SLRM-080A Sh. 2

12050-SLRM-074A Sh. 1

12050-SLRM-074A Sh. 2

12050-SLRM-074A Sh. 3

12050-SLRM-074A Sh. 4

12050-SLRM-074B Sh. 1

12050-SLRM-074C Sh. 1

12050-SLRM-080A Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-5, Feedwater.

The aging management review results for these component types are indicated in Table 3.4.2-5, Steam and Power Conversion System - Feedwater - Aging Management Evaluation.

2.3.4.6 Condensate

System Description

The primary purpose of the condensate system is to provide chemically treated water to the suction of the main feedwater pumps at sufficient pressure to support main feedwater pump operation.

The condensate system also provides the piping, valves, water storage, and make-up supply for auxiliary feedwater. An emergency condensate storage tank is provided for each unit. Each tank supplies water to the three auxiliary steam generator feed pumps through individual lines.

System Evaluation Boundary

The evaluation boundary for the condensate system components subject to aging management review includes the safety-related condensate storage tank and its makeup supply from the condensate makeup header, and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water or steam in buildings containing safety-related components.

System Intended Functions

The condensate system performs the following safety-related functions: The system provides a source of water to the auxiliary feedwater pumps, and provides non-EQ safety-related instrumentation. Therefore, the condensate system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The condensate system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the condensate system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction and structural integrity.

The condensate system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, the condensate system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the condensate system can be found in the UFSAR, Section 10.4.3 and Table 10.4-2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the condensate system are listed below:

11715-SLRM-072A Sh. 2

11715-SLRM-074A Sh. 3

11715-SLRM-080A Sh. 1

11715-SLRM-73A Sh. 1

11715-SLRM-73A Sh. 2

11715-SLRM-73D Sh. 1

12050-SLRM-072A Sh. 2

12050-SLRM-074A Sh. 3

12050-SLRM-080A Sh. 1

12050-SLRM-73A Sh. 1

12050-SLRM-73A Sh. 2

12050-SLRM-73C Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-6, Condensate.

The aging management review results for these component types are indicated in Table 3.4.2-6, Steam and Power Conversion System - Condensate - Aging Management Evaluation.

2.3.4.7 Condensate Polishing

System Description

The condensate polishing system consists of five powdered-resin filter demineralizers designed to remove impurities from the condensate stream, which result from condenser tube leakage, and produce a high-quality effluent within the feedwater and steam generator chemistry specifications.

System Evaluation Boundary

The evaluation boundary for the condensate polishing system components subject to aging management review includes nonsafety-related components that retain water in buildings containing safety-related components.

System Intended Functions

The condensate polishing system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the condensate polishing system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

UFSAR References

Additional details of the condensate polishing system can be found in the UFSAR, Section 10.4.8.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the condensate polishing system are listed below:

11715-SLRM-73B Sh. 1

11715-SLRM-73B Sh. 4

12050-SLRM-73B Sh. 1

12050-SLRM-73B Sh. 4

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-7, Condensate Polishing.

The aging management review results for these component types are indicated in Table 3.4.2-7, Steam and Power Conversion System - Condensate Polishing - Aging Management Evaluation.

2.3.4.8 Steam Drains

System Description

The steam drains system collects drains from the secondary plant and returns them to the feedwater or condensate system. Drains from the moisture separator reheaters, and the first-point and second-point feedwater heaters are collected in the high-pressure heater drain receivers and pumped into the suction of the feedwater pumps by three full-size high-pressure heater drain pumps. Drains from the low-pressure feedwater heaters are collected and routed to the condensate system.

The steam drains system also provides flowpaths for venting of the moisture separator reheaters and feedwater heaters.

System Evaluation Boundary

The evaluation boundary for the steam drains system components subject to aging management review includes nonsafety-related components that retain water, steam or oil in buildings containing safety-related components. All of the safety-related mechanical components of the steam drains system (piping, piping components) are within the evaluation boundary of the main steam system, and no other mechanical components support the safety-related instrumentation function.

System Intended Functions

The steam drains system performs the following safety-related function: The system provides non-EQ safety-related instrumentation. Therefore, the steam drains system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The steam drains system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the steam drains system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

UFSAR References

Additional details of the steam drains system can be found in the UFSAR, Section 10.1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the steam drains system are listed below:

11715-SLRM-072A Sh. 2

11715-SLRM-75A Sh. 1

11715-SLRM-75A Sh. 2

11715-SLRM-75A Sh. 3

11715-SLRM-75A Sh. 4

11715-SLRM-76A Sh. 1

11715-SLRM-76A Sh. 2

11715-SLRM-85A Sh. 1

12050-SLRM-072A Sh. 2

12050-SLRM-75A Sh. 1

12050-SLRM-75A Sh. 2

12050-SLRM-75A Sh. 3

12050-SLRM-76A Sh. 1

12050-SLRM-76A Sh. 2

12050-SLRM-76A Sh. 3

12050-SLRM-76C Sh.1

12050-SLRM-85A Sh. 1

12050-SLRM-85A Sh. 2

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-8, Steam Drains.

The aging management review results for these component types are indicated in Table 3.4.2-8, Steam and Power Conversion System - Steam Drains - Aging Management Evaluation.

2.3.4.9 Blowdown

System Description

The blowdown system provides a flowpath for the continuous blowdown flow from the steam generator secondary-side to maintain acceptable steam generator water chemistry. The blowdown system isolates flow for containment isolation, to maintain steam generator inventory during transients, and in the event of a high energy line break.

System Evaluation Boundary

The evaluation boundary for the blowdown system components subject to aging management review includes the safety-related components from the steam generators to the outboard containment isolation valves, the nonsafety-related steam generator blowdown vent condenser that supports the safety-related system integrity of the component cooling system, and nonsafety-related components that provide support to directly-connected safety-related components, or that retain water or steam in buildings containing safety-related components. Thermal insulation on blowdown lines within containment penetrations is also subject to aging management review.

System Intended Functions

The blowdown system performs the following safety-related functions: The system will automatically isolate the steam generator on a Phase A signal, on auxiliary feedwater auto-start, or on a high-flow trip signal; can be manually isolated (e.g., recovery from steam generator tube rupture); provides non-EQ safety-related instrumentation; and provides containment isolation. Therefore, the blowdown system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The blowdown system contains nonsafety-related system pressure boundary components that support safety-related system integrity. The system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the blowdown system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for pressure boundary integrity, spatial interaction and structural integrity.

The blowdown system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the blowdown system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the blowdown system can be found in the UFSAR, Sections 7.7.1.14, 10.4.6, and 15.4.3, and Table 6.2-37.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the blowdown system are listed below:

11715-SLRM-077A Sh. 2

11715-SLRM-098A Sh. 1

11715-SLRM-098A Sh. 2

11715-SLRM-098A Sh. 3

11715-SLRM-098A Sh. 4

11715-SLRM-098A Sh. 5

12050-SLRM-077A Sh. 2

12050-SLRM-098A Sh. 1

12050-SLRM-098A Sh. 2

12050-SLRM-098A Sh. 3

12050-SLRM-098A Sh. 4

12050-SLRM-098A Sh. 5

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-9, Blowdown.

The aging management review results for these component types are indicated in Table 3.4.2-9, Steam and Power Conversion System - Blowdown - Aging Management Evaluation.

2.3.4.10 Lubricating Oil

System Description

The lubricating oil system provides all lubricating oil requirements for the main turbine-generator units. A turbine shaft-driven main oil pump normally takes oil from the turbine lube oil reservoir and supplies it to the nine bearing housings for each turbine-generator unit.

System Evaluation Boundary

The evaluation boundary for the lubricating oil system components subject to aging management review includes nonsafety-related components that retain water or oil in buildings containing safety-related components. There are no passive mechanical components in the lubricating oil system whose integrity is relied upon to support safety-related functions.

System Intended Functions

The lubricating oil system performs the following safety-related functions: The system provides non-EQ safety-related instrumentation. Therefore, the lubricating oil system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The lubricating oil system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the lubricating oil system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

UFSAR References

Additional details of the lubricating oil system can be found in the UFSAR, Sections 10.2 and 10.4.5.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the lubricating oil system are listed below:

11715-SLRM-083A Sh. 1

11715-SLRM-083B Sh. 1

11715-SLRM-083C Sh. 1

11715-SLRM-110A Sh. 1

12050-SLRM-083B Sh. 1

12050-SLRM-110A Sh. 1

12050-SLRM-83A Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-10, Lubricating Oil.

The aging management review results for these component types are indicated in Table 3.4.2-10, Steam and Power Conversion System - Lubricating Oil - Aging Management Evaluation.

2.3.4.11 Main Generator Seal Oil

System Description

The main generator seal oil system provides seal oil for the prevention of hydrogen leakage from the main generators. Hydrogen-side and air-side AC motor-driven seal oil pumps are furnished to provide seal oil to the main generator. A DC air-side seal oil backup pump, powered from the station battery, is also provided. Backup is also provided from the turbine-generator lubricating oil system from a variety of sources. Backup is normally provided by the main oil pump. During periods of start-up, shutdown, or turning gear operation, backup is provided by an AC motor-driven seal oil backup pump or the bearing oil pump. During a loss-of-station-power incident, seal oil is provided by the DC air-side seal oil backup pump, and backup is provided by the DC emergency oil pump.

System Evaluation Boundary

The evaluation boundary for the main generator seal oil system components subject to aging management review includes nonsafety-related components that retain water or oil in buildings containing safety-related components.

System Intended Functions

The main generator seal oil system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the main generator seal oil system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

UFSAR References

Additional details of the main generator seal oil system can be found in the UFSAR, Section 10.2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the main generator seal oil system are listed below:

11715-SLRM-080A Sh. 1

11715-SLRM-080A Sh. 2

11715-SLRM-104A Sh. 1

11715-SLRM-104B Sh. 1

11715-SLRM-110A Sh. 1

12050-SLRM-080A Sh. 1

12050-SLRM-080A Sh. 2

12050-SLRM-104A Sh. 1

12050-SLRM-110A Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-11, Main Generator Seal Oil.

The aging management review results for these component types are indicated in Table 3.4.2-11, Steam and Power Conversion System - Main Generator Seal Oil - Aging Management Evaluation.

2.3.4.12 Electro-Hydraulic Control

System Description

The electro-hydraulic control system controls the operation of the main turbine throttle, governor, reheat stop and intercept valves to control turbine speed, to control power output, and to trip the turbine when needed.

System Evaluation Boundary

The evaluation boundary for the electro-hydraulic control system components subject to aging management review includes nonsafety-related components that contain hydraulic fluid in buildings containing safety-related components.

There are no passive mechanical components in the electro-hydraulic control system whose integrity is relied upon to support safety-related functions or the turbine trip function.

System Intended Functions

The electro-hydraulic control system contains nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the electro-hydraulic control system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for spatial interaction.

The electro-hydraulic control system is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Anticipated Transients Without Scram (10 CFR 50.62). Therefore, the electro-hydraulic control system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the electro-hydraulic control system can be found in the UFSAR, Section 10.2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the electro-hydraulic control system are listed below:

11715-SLRM-109A Sh. 1

12050-SLRM-109A Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.3.4-12, Electro-Hydraulic Control.

The aging management review results for these component types are indicated in Table 3.4.2-12, Steam and Power Conversion System - Electro-Hydraulic Control - Aging Management Evaluation.

Screening Results Tables: Steam and Power Conversion Systems

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-1 Main Steam

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Expansion joint	Leakage Boundary (Spatial)
Flow element	Pressure Boundary, Restricts Flow
Heat exchanger (moisture separator reheater - channel)	Leakage Boundary (Spatial)
Heat exchanger (moisture separator reheater - shell)	Leakage Boundary (Spatial)
Insulation (containment penetration)	Thermal insulation
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Rupture disc	Leakage Boundary (Spatial)
Steam chest	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial), Pressure Boundary
Trap body	Leakage Boundary (Spatial), Pressure Boundary
Turbine casing (auxiliary feed pump)	Pressure Boundary
Turbine casing (high pressure)	Leakage Boundary (Spatial)
Turbine casing (low pressure)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary
Venturi	Restricts Flow

See Table 2.1-1 for definitions of intended functions.

The aging management review results for these component types are indicated in Table 3.4.2-1, Steam and Power Conversion System - Main Steam - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-2 Auxiliary Boilers

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Deaerator	Leakage Boundary (Spatial)
Expansion joint	Leakage Boundary (Spatial)
Flexible hose	Leakage Boundary (Spatial)
Heat exchanger (auxiliary boiler - steam drum)	Leakage Boundary (Spatial)
Heat exchanger (auxiliary boiler - wind box)	Leakage Boundary (Spatial)
Heat exchanger (auxiliary boiler fuel oil - channel)	Leakage Boundary (Spatial)
Heat exchanger (auxiliary boiler fuel oil - shell)	Leakage Boundary (Spatial)
Heat exchanger (auxiliary boiler)	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Oxygen gun	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (ammonia feed)	Leakage Boundary (Spatial)
Pump casing (boiler feed)	Leakage Boundary (Spatial)
Pump casing (condensate return)	Leakage Boundary (Spatial)
Pump casing (fuel oil)	Leakage Boundary (Spatial)
Pump casing (hydrazine feed)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-2 Auxiliary Boilers

Component Type	Intended Function(s)
Sight glass (body)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (ammonia feed)	Leakage Boundary (Spatial)
Tank (blowdown)	Leakage Boundary (Spatial)
Tank (hydrazine feed)	Leakage Boundary (Spatial)
Tank (measuring)	Leakage Boundary (Spatial)
Tank (oil reservoir)	Leakage Boundary (Spatial)
Trap body	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.4.2-2, Steam and Power Conversion System - Auxiliary Boilers - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-3 Extraction Steam

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Expansion joint	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Trap body	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.4.2-3, Steam and Power Conversion System - Extraction Steam - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-4 Auxiliary Steam

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Moisture separator	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (auxiliary steam drain receiver)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (auxiliary steam drain receiver)	Leakage Boundary (Spatial)
Trap body	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.4.2-4, Steam and Power Conversion System - Auxiliary Steam - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-5 Feedwater

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Filter housing	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Flow element	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Heat exchanger (auxiliary feedwater pump lube oil cooler - channel)	Pressure Boundary
Heat exchanger (auxiliary feedwater pump lube oil cooler - shell)	Pressure Boundary
Heat exchanger (auxiliary feedwater pump lube oil cooler - tube)	Heat Transfer, Pressure Boundary
Heat exchanger (auxiliary feedwater pump lube oil cooler - tubesheet)	Pressure Boundary
Heat exchanger (first point feedwater heater - channel)	Leakage Boundary (Spatial)
Heat exchanger (first point feedwater heater - shell)	Leakage Boundary (Spatial)
Heat exchanger (main feed pump stuffing box jacket)	Leakage Boundary (Spatial)
Heat exchanger (main feedwater pump lube oil cooler - channel)	Leakage Boundary (Spatial)
Heat exchanger (main feedwater pump lube oil cooler - shell)	Leakage Boundary (Spatial)
Heat exchanger (main feedwater pump seal cooler - channel)	Leakage Boundary (Spatial)
Heat exchanger (main feedwater pump seal cooler - shell)	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-5 Feedwater

Component Type	Intended Function(s)
Insulation (containment penetration)	Thermal insulation
Orifice	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)
Positioner	Structural Integrity (Attached)
Pump casing (auxiliary feedwater pump oil)	Leakage Boundary (Spatial)
Pump casing (main feedwater pump oil)	Leakage Boundary (Spatial)
Pump casing (main feedwater)	Leakage Boundary (Spatial)
Pump casing (motor-driven auxiliary feedwater)	Pressure Boundary
Pump casing (turbine-driven auxiliary feedwater)	Pressure Boundary
Sight glass	Leakage Boundary (Spatial), Pressure Boundary
Sight glass (body)	Leakage Boundary (Spatial), Pressure Boundary
Tank (instrument air accumulator)	Pressure Boundary
Tank (main feed pump lube oil reservoir)	Leakage Boundary (Spatial)
Tank (motor-driven pump lube oil reservoir)	Pressure Boundary
Tank (turbine-driven pump lube oil reservoir)	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary, Structural Integrity (Attached)

See Table 2.1-1 for definitions of intended functions.

The aging management review results for these component types are indicated in Table 3.4.2-5, Steam and Power Conversion System - Feedwater - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-6 Condensate

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Expansion joint	Leakage Boundary (Spatial)
Flexible hose	Leakage Boundary (Spatial)
Heat exchanger (air ejector)	Leakage Boundary (Spatial)
Heat exchanger (condensate drain cooler - channel)	Leakage Boundary (Spatial)
Heat exchanger (condensate drain cooler - shell)	Leakage Boundary (Spatial)
Heat exchanger (feedwater heater - channel)	Leakage Boundary (Spatial)
Heat exchanger (feedwater heater - shell)	Leakage Boundary (Spatial)
Heat exchanger (gland steam condenser - shell)	Leakage Boundary (Spatial)
Heat exchanger (gland steam condenser - waterbox)	Leakage Boundary (Spatial)
Heat exchanger (main condenser - hotwell)	Leakage Boundary (Spatial)
Heat exchanger (main condenser - shell)	Leakage Boundary (Spatial)
Manway	Pressure Boundary
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-6 Condensate

Component Type	Intended Function(s)
Piping, piping components (exiting concrete into soil)	Leakage Boundary (Spatial)
Pump casing (condensate)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (emergency condensate storage (110k gal))	Pressure Boundary
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.4.2-6, Steam and Power Conversion System - Condensate - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-7 Condensate Polishing

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Cation column	Leakage Boundary (Spatial)
Demineralizer shell	Leakage Boundary (Spatial)
Drip pan	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Flow element	Leakage Boundary (Spatial)
Heat exchanger (sample cooler - shell)	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (backwash recovery)	Leakage Boundary (Spatial)
Pump casing (backwash)	Leakage Boundary (Spatial)
Pump casing (hold pump)	Leakage Boundary (Spatial)
Pump casing (precoat)	Leakage Boundary (Spatial)
Pump casing (spent resin transfer)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (A recovery compartment)	Leakage Boundary (Spatial)
Tank (B recovery compartment)	Leakage Boundary (Spatial)
Tank (precoat)	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-7 Condensate Polishing

Component Type	Intended Function(s)
Tank (secondary phase separator)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.4.2-7, Steam and Power Conversion System - Condensate Polishing - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-8 Steam Drains

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Expansion joint	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Flow element	Leakage Boundary (Spatial)
Heat exchanger (heater drain pump lube oil cooler - channel)	Leakage Boundary (Spatial)
Heat exchanger (heater drain pump lube oil cooler - shell)	Leakage Boundary (Spatial)
Level indicator	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (high-pressure heater drain - head assembly)	Leakage Boundary (Spatial)
Pump casing (high-pressure heater drain)	Leakage Boundary (Spatial)
Pump casing (low-pressure heater drain)	Leakage Boundary (Spatial)
Pump casing (shaft-driven lube oil pump)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (2nd point heater drain receiver)	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-8 Steam Drains

Component Type	Intended Function(s)
Tank (lube oil reservoir)	Leakage Boundary (Spatial)
Tank (MSR drain receiver)	Leakage Boundary (Spatial)
Tank (reheater drain receiver)	Leakage Boundary (Spatial)
Trap body	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.4.2-8, Steam and Power Conversion System - Steam Drains - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-9 Blowdown

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial), Pressure Boundary
Flow element	Leakage Boundary (Spatial)
Heat exchanger (blowdown flash tank drains - channel)	Leakage Boundary (Spatial)
Heat exchanger (blowdown flash tank drains - shell)	Leakage Boundary (Spatial)
Heat exchanger (blowdown vent condenser - channel)	Leakage Boundary (Spatial)
Heat exchanger (blowdown vent condenser - shell)	Leakage Boundary (Spatial)
Insulation (containment penetration)	Thermal insulation
Orifice	Leakage Boundary (Spatial), Pressure Boundary, Restricts Flow
Piping, piping components	Leakage Boundary (Spatial), Pressure Boundary
Pump casing (sampling transfer)	Leakage Boundary (Spatial)
Radiation monitor housing	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Tank (blowdown flash)	Leakage Boundary (Spatial)
Tank (condensate pot)	Leakage Boundary (Spatial)
Tank (proportional sampler)	Leakage Boundary (Spatial)
Tank (steam generator blowdown)	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-9 Blowdown

Component Type	Intended Function(s)
Valve body	Leakage Boundary (Spatial), Pressure Boundary

The aging management review results for these component types are indicated in Table 3.4.2-9, Steam and Power Conversion System - Blowdown - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-10 Lubricating Oil

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Flow element	Leakage Boundary (Spatial)
Heat exchanger (turbine lube oil cooler - channel)	Leakage Boundary (Spatial)
Heat exchanger (turbine lube oil cooler - shell)	Leakage Boundary (Spatial)
Heater housing	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (bearing oil lift)	Leakage Boundary (Spatial)
Pump casing (conditioner skid)	Leakage Boundary (Spatial)
Pump casing (conditioner supply)	Leakage Boundary (Spatial)
Pump casing (fill)	Leakage Boundary (Spatial)
Pump casing (main lube oil)	Leakage Boundary (Spatial)
Pump casing (seal oil backup)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)
Strainer body	Leakage Boundary (Spatial)
Tank (clean oil tank)	Leakage Boundary (Spatial)
Tank (turbine lube oil reservoir)	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-10 Lubricating Oil

Component Type	Intended Function(s)
Tank (used oil tank)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.4.2-10, Steam and Power Conversion System - Lubricating Oil - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-11 Main Generator Seal Oil

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Flexible hose	Leakage Boundary (Spatial)
Heat exchanger (air side oil cooler - channel)	Leakage Boundary (Spatial)
Heat exchanger (air side oil cooler - shell)	Leakage Boundary (Spatial)
Heat exchanger (exciter air cooler - channel)	Leakage Boundary (Spatial)
Heat exchanger (exciter air cooler - tube)	Leakage Boundary (Spatial)
Heat exchanger (generator leads cooler - channel)	Leakage Boundary (Spatial)
Heat exchanger (generator leads cooler - tube)	Leakage Boundary (Spatial)
Heat exchanger (hydrogen side oil cooler - channel)	Leakage Boundary (Spatial)
Heat exchanger (hydrogen side oil cooler - shell)	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (air side seal oil)	Leakage Boundary (Spatial)
Pump casing (hydrogen side seal oil)	Leakage Boundary (Spatial)
Sight glass	Leakage Boundary (Spatial)
Sight glass (body)	Leakage Boundary (Spatial)

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-11 Main Generator Seal Oil

Component Type	Intended Function(s)
Tank (dryer vent condensate drain)	Leakage Boundary (Spatial)
Tank (generator loop seal)	Leakage Boundary (Spatial)
Tank (hydrogen side drain regulator)	Leakage Boundary (Spatial)
Tank (hydrogen side receiver)	Leakage Boundary (Spatial)
Tank (prefilter sump)	Leakage Boundary (Spatial)
Tank (water detector)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.4.2-11, Steam and Power Conversion System - Main Generator Seal Oil - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.3.4-12 Electro-Hydraulic Control

Component Type	Intended Function(s)
Bolting	Leakage Boundary (Spatial)
Filter housing	Leakage Boundary (Spatial)
Filter housing (duplex filter - head)	Leakage Boundary (Spatial)
Filter housing (duplex filter)	Leakage Boundary (Spatial)
Flexible hose	Leakage Boundary (Spatial)
Flow element	Leakage Boundary (Spatial)
Heat exchanger (EHC cooler - channel)	Leakage Boundary (Spatial)
Heat exchanger (EHC cooler - shell)	Leakage Boundary (Spatial)
Orifice	Leakage Boundary (Spatial)
Piping, piping components	Leakage Boundary (Spatial)
Pump casing (EHC pump)	Leakage Boundary (Spatial)
Tank (EHC reservoir)	Leakage Boundary (Spatial)
Tank (high-pressure accumulator)	Leakage Boundary (Spatial)
Tank (low-pressure accumulator)	Leakage Boundary (Spatial)
Valve body	Leakage Boundary (Spatial)

The aging management review results for these component types are indicated in Table 3.4.2-12, Steam and Power Conversion System - Electro-Hydraulic Control - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Intentionally Blank

See Table 2.1-1 for definitions of intended functions.

2.4 SCOPING AND SCREENING RESULTS: STRUCTURES

2.4.1 CONTAINMENTS, STRUCTURES, AND COMPONENT SUPPORTS

2.4.1.1 Containment

System Description

The Unit 1 and Unit 2 Containments are safety-related structures that house the reactor vessel and other nuclear steam supply system components for the respective unit. Each Containment consists of a reinforced concrete cylinder with a hemispherical dome and a flat, 10-foot-thick reinforced concrete mat foundation.

The Containments are founded on crystalline, metamorphic rock, and beneath the Containments, a 6-inch layer of porous concrete was placed directly on the rock surface. A waterproof membrane was laid directly on top of this layer of porous concrete; then another 4-inch layer of porous concrete was poured on top of the membrane and the reinforced concrete mat foundation was placed on top of the porous concrete. The waterproof membrane generally extends up the Containment wall to 6 inches below ground grade. Located inside the waterproof membrane are Containment mat subsurface pump access shafts, which house pumps that minimize the hydrostatic pressure on the Containment liner.

Attached to the inside of the cylindrical Containment wall and dome is a steel liner of varying thickness. The liner is attached to the cylindrical wall and dome with concrete anchors and deformed anchor bars that were cast in the concrete as the concrete was poured against the liner. Individual liner plates are connected by full penetration welds to form a leak-tight barrier. Leak tightness testing of liner welds during construction was performed by welding a structural steel test channel over the weld seams. The Containment basemat liner leak chase channel test connections are regarded as moisture barriers.

Steel insert plates are used in the Containment liner to attach equipment supports. Equipment support loads are transferred to the Containment concrete wall through the insert plates and their anchors.

The bottom of the Containment liner is covered with a reinforced concrete slab for protection, except the portion directly below the reactor vessel. The Containment is divided by the crane wall that supports the polar crane into an outer annulus section, and a central section. The central section is further subdivided into equipment cubicles that are connected to each other and to the outer annulus by open archways, grating floors, and unsealed penetrations. A drainage sump with a stainless steel liner is provided in the Containment basement for collecting liquid wastes.

Each Containment contains a personnel air lock and an equipment hatch access opening. The personnel air lock has an inner and an outer door that are electrically interlocked so that only one door may be open at a time. Both the inner and outer doors are sealed with sets of double O-rings. The space between the O-rings can be pressurized for leak rate testing. Each of these doors has an emergency escape hatch, which has a closure design similar to the one on the personnel air locks.

The equipment hatch in each Containment is a large diameter single-door hatch that is sized to permit removal of large components. The hatch cover is double gasketed with a leakage test tap between the O-rings. The enclosed space between the O-rings can be pressurized to Containment design pressure to test for leakage when the access door is bolted in place. The equipment hatch includes a two-door emergency personnel escape lock. The escape lock is attached to the equipment hatch by double gasketed bolted flanges. Test taps for conducting leakage measurements are provided.

Located outside, but in front of each equipment hatch, is a concrete missile shield, which is supported by the equipment hatch platform. The equipment hatch platform is a steel structure and is supported by structural framing consisting of steel beams and columns.

The Containment has numerous electrical and mechanical piping penetrations that form part of the Containment pressure boundary. The penetrations are welded to the containment liner and provide a seal between Containment and the outside atmosphere. Electrical penetrations provide the means for electrical and instrumentation conductors to cross the Containment boundary while maintaining the essentially leak-tight barrier. Mechanical piping penetrations provide the means for passage of process piping transmitting liquids or gases across the Containment boundary.

A fuel transfer tube penetration is provided in the Containment to permit fuel movement between the refueling canal in the Containment and the spent fuel pool in the Fuel Building. The fuel transfer tube assembly is capped with a blind flange and forms part of the Containment pressure boundary. The fuel transfer tube assembly and blind flange are evaluated with the fuel handling system. A protection shield encloses the fuel transfer tube at the Containment and Fuel Building interface. The fuel transfer tube enclosure protection shield is evaluated with the Containment.

A reinforced concrete reactor cavity with a stainless steel liner is provided in the Containment for refueling. The reactor cavity is located above the reactor vessel flange and is normally dry, but is filled with treated borated water for refueling. Prior to refueling, a reactor cavity seal is installed between the reactor vessel flange and the reactor cavity, which prevents leakage of refueling water from the cavity.

The reactor vessel head replacement project created and restored a construction opening in the Containment in accordance with administrative procedures and the design control program. The opening was used to facilitate the movement of original and replacement reactor vessel heads in and out of the Containment. The opening was restored to meet the original design bases of the Containment.

Service Level I coatings are used in areas inside the Containment (e.g., steel liner, penetrations, and concrete walls and floors).

System Evaluation Boundary

The evaluation boundary for the Containment subject to aging management review includes bolting; concrete elements associated with beams, columns, walls, slabs, curbs, foundations, pads, dikes, jet impingement barriers, missile barriers, and the exterior concrete for Containment; Containment liner which includes liner plates, basemat liner leak chase channel test connections, liner anchors, and integral attachments; Containment sump liner; equipment hatch, personnel air lock, emergency escape locks, and accessories (hinges, pins, closure mechanisms); fuel transfer tube enclosure protection shield; penetrations (electrical); penetrations (mechanical); porous concrete; reactor cavity liner; seals and gaskets which include O-rings for personnel air locks, equipment hatches, emergency escape locks, penetration flanges, fuel transfer tube blind flange, and other elastomer materials that are part of the Containment pressure boundary; Service Level I coatings; steel elements associated with beams, columns, baseplates, bracing, stairs, platforms, grating, decking, ladders, doors, missile barriers, and embedded steel; and waterproofing membrane.

For mechanical penetrations, flued heads and isolation valves are evaluated with the host system. Electrical penetration assemblies are within the scope of the EQ program. The portions of the electrical penetrations that form part of the Containment pressure boundary are included within the Containment evaluation boundary. The fuel transfer tube assembly and blind flange are evaluated with the fuel handling system. Fuel transfer tube supports are evaluated with component supports. The sump screen assemblies installed to prevent debris from entering the Containment sump are evaluated with the recirculation spray system. The Containment mat subsurface pump access shafts are evaluated with yard structures and the Containment mat subsurface pumps are evaluated with the drains aerated system.

System Intended Functions

The Containment performs the following safety-related functions: The structure provides structural support, shelter and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, the Containment is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Containment provides structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Containment is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Containment is relied upon for compliance with regulations for: Fire Protection (10 CFR 50.48), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the Containment is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Containment can be found in the UFSAR, Sections 3.1.12, 3.8.2, and 6.1; and Figures 3.8-2 through 3.8-22.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Containment are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-1, Containment.

The aging management review results for these component types are indicated in Table 3.5.2-1, Containment Structure - Aging Management Evaluation.

2.4.1.2 Administration Building

System Description

The Administration Building, also known as the Office Building, is common to both units and is located east of the Unit 1 Turbine Building. The Administration Building is a two-story structure founded on reinforced concrete piers and grade beams on compacted soil. The structure is enclosed with metal siding and masonry block walls. The roof consists of metal decking covered with a built-up roof. The intermediate floor is constructed of reinforced concrete and is supported by steel framing.

System Evaluation Boundary

The evaluation boundary for the Administration Building includes bolting; concrete elements associated with walls, slabs, and foundations; doors; masonry block walls; roofing membrane elements; and steel elements associated with beams, columns, siding, baseplates, decking, and embedded steel.

System Intended Functions

The Administration Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Administration Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Administration Building can be found in the UFSAR, Appendix 2C; Sections 1.2.11, 9.2.4, and 9.5.1.2.1; and Table 9.5-7.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Administration Building are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-2, Administration Building.

The aging management review results for these component types are indicated in Table 3.5.2-2, Structures and Component Supports - Administration Building - Aging Management Evaluation.

2.4.1.3 Auxiliary Building

System Description

The Auxiliary Building is common to both units and is located between the Unit 1 and Unit 2 Containments. The Auxiliary Building is a multi-story structure and the following areas are included as part of the Auxiliary Building:

- Cable tunnels
- Cable vaults
- Hydrogen recombiner vault
- Pipe tunnels
- Rod drive rooms (also known as the Motor Control Center rooms)

The above structures are on a common foundation. The term Auxiliary Building should be understood to include these rooms or areas unless specified otherwise.

The Auxiliary Building has a reinforced concrete mat foundation supported primarily on rock. The lower two stories are below grade (substructure). Substructure walls are constructed of reinforced concrete or masonry blocks. The third and fourth stories consist of a structural steel framed superstructure that is enclosed with metal siding and metal roof decking. The roof is comprised of steel framing covered with steel decking and a mechanically attached membrane. Intermediate concrete floor slabs are cast on metal deck forms, which remain in place, or they are cast on removable form work supported by scaffolding. Portions of the roof and walls are reinforced concrete designed for missile shield and tornado loads. Internally, reinforced concrete walls and slabs are provided for enclosing components for biological and missile shielding.

Rolling steel and metal doors are provided for access to the Auxiliary Building. Flood protection barriers; fire, EQ, and missile-protected doors; fire barrier penetrations; and fire barrier seals are provided to protect safety-related equipment.

The cable vault, cable tunnel, rod drive room and pipe tunnel for each unit are reinforced concrete structures. For each structure, the pipe tunnel is in the lower story, the cable vault and cable tunnel are in the intermediate story, and the rod drive room is in the uppermost story.

The hydrogen recombiner vault is a single-story structure that houses the hydrogen recombiners. The hydrogen recombiner vault is located above the Unit 2 cable tunnel and is attached to the east side of the Unit 2 rod drive room.

System Evaluation Boundary

The evaluation boundary for the Auxiliary Building includes aluminum elements that include louvers and screens; bolting; concrete elements associated with beams, columns, foundation, walls, hatches, missile barriers, pads, and slabs; doors; masonry block walls; roofing membrane; and steel elements associated with beams, columns, ladders, stairs, baseplates, decking, grating, siding, dikes, missile shields, and embedded steel.

System Intended Functions

The Auxiliary Building performs the following safety-related functions: The structure provides structural support, shelter and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, the Auxiliary Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Auxiliary Building provides structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Auxiliary Building is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Auxiliary Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the Auxiliary Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Auxiliary Building can be found in the UFSAR, Sections 1.2, 2.4, 2.5, 3.7, 3.8.1, 3.8.5, 9.4, and 9.5; and Table 3.2-1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Auxiliary Building are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-3, Auxiliary Building.

The aging management review results for these component types are indicated in Table 3.5.2-3, Structures and Component Supports - Auxiliary Building - Aging Management Evaluation.

2.4.1.4 Auxiliary Feedwater Pump House

System Description

An Auxiliary Feedwater Pump House is provided for each unit. The Unit 1 Auxiliary Feedwater Pump House is located east of Unit 1 Containment, and Unit 2 Auxiliary Feedwater Pump House is located west of Unit 2 Containment. Each Auxiliary Feedwater Pump House is a single-story reinforced concrete structure, divided into two pump cubicles separated by a concrete wall. The building is founded at grade on a reinforced concrete mat foundation with the Unit 1 foundation on rock; and the Unit 2 foundation is partially on rock, and partially on concrete backfill, which extends down to underlying rock. The Auxiliary Feedwater Pump House is a tornado-missile-protected structure. There are missile-protected concrete hatches in the roof openings.

System Evaluation Boundary

The evaluation boundary for the Auxiliary Feedwater Pump House includes bolting; concrete elements associated with foundation, internal structural members, walls, pads, hatches, and roof slabs; and steel elements associated with doors, beams, baseplates, grating, screens, and embedded steel.

System Intended Functions

The Auxiliary Feedwater Pump House performs the following safety-related functions: The structure provides structural support, shelter and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, the Auxiliary Feedwater Pump House is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Auxiliary Feedwater Pump House provides structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Auxiliary Feedwater Pump House is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Auxiliary Feedwater Pump House is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the Auxiliary Feedwater Pump House is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Auxiliary Feedwater Pump House can be found in the UFSAR, Section 9.5.1.3.1.3 and Table 3.2-1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Auxiliary Feedwater Pump House are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-4, Auxiliary Feedwater Pump House.

The aging management review results for these component types are indicated in Table 3.5.2-4, Structures and Component Supports - Auxiliary Feedwater Pump House - Aging Management Evaluation.

2.4.1.5 Auxiliary Feedwater Tunnel

System Description

An Auxiliary Feedwater Tunnel is provided for each unit. Each Auxiliary Feedwater Tunnel runs between the Quench Spray Pump House and the Auxiliary Feedwater Pump House for the respective unit. The Auxiliary Feedwater Tunnels are reinforced concrete structures that are primarily below grade. The tunnels provide missile protection for enclosed safety-related piping and missile-protected manhole covers are provided at grade elevation for access. The Unit 1 Auxiliary Feedwater Tunnel is partially founded on rock, and partially founded on soil. The Unit 2 Auxiliary Feedwater Tunnel is founded on soil.

System Evaluation Boundary

The evaluation boundary of the Auxiliary Feedwater Tunnels includes bolting; concrete elements associated with walls, slabs, and foundations; stainless steel elements associated with missile barriers; and steel elements associated with manhole covers, ladders, baseplates, and embedded steel.

System Intended Functions

The Auxiliary Feedwater Tunnels perform the following safety-related functions: The structures provide structural support, shelter and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, the Auxiliary Feedwater Tunnels are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Auxiliary Feedwater Tunnels provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Auxiliary Feedwater Tunnels are within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Auxiliary Feedwater Tunnels are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, the Auxiliary Feedwater Tunnels are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Auxiliary Feedwater Tunnel can be found in the UFSAR, Appendix 3C.5.4.9 and Table 2.4-7.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Auxiliary Feedwater Tunnel are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-5, Auxiliary Feedwater Tunnel.

The aging management review results for these component types are indicated in Table 3.5.2-5, Structures and Component Supports - Auxiliary Feedwater Tunnel - Aging Management Evaluation.

2.4.1.6 Boron Recovery Building

System Description

The Boron Recovery Building is common to both units and is located in the south yard adjacent to the Waste Disposal Building. The Boron Recovery Building is a single-story structure that is supported by concrete footings founded on rock, and enclosed by concrete walls up to a height of 15 feet above grade. The remaining upper wall structure is a steel-framed structure with metal siding. The roof system consists of metal decking covered with a built-up roof. Interior walls divide the building into three cubicles, each of which houses one boron recovery tank.

System Evaluation Boundary

The evaluation boundary for the Boron Recovery Building includes aluminum elements that include louvers and screens; bolting; concrete elements associated with walls, slabs, foundation, pads, and dikes; roofing membrane; and steel elements associated with beams, columns, doors, baseplates, decking, siding, and embedded steel.

System Intended Functions

The Boron Recovery Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Boron Recovery Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Boron Recovery Building can be found in the UFSAR, Sections 3.8.1.1 and 11.3.5.2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Boron Recovery Building are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-6, Boron Recovery Building.

The aging management review results for these component types are indicated in Table 3.5.2-6, Structures and Component Supports - Boron Recovery Building - Aging Management Evaluation.

2.4.1.7 Casing Cooling Pump House

System Description

A Casing Cooling Pump House is provided for each unit and each is located in the yard south of the Auxiliary Feedwater Pump House for its respective unit. Each Casing Cooling Pump House is a single-story reinforced concrete structure founded at grade on a concrete mat foundation, which is common foundation with the Casing Cooling Tank foundation. It has a built-up metal deck roof that is supported by the concrete walls and structural steel framing.

System Evaluation Boundary

The evaluation boundary for the Casing Cooling Pump House includes aluminum elements that include louvers and screens; bolting; concrete elements associated with foundation, walls, pads, and slabs; roofing membrane; and steel elements associated with beams, columns, doors, baseplates, grating, and embedded steel.

System Intended Functions

The Casing Cooling Pump House performs the following safety-related functions: The structure provides structural support, shelter and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, the Casing Cooling Pump House is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Casing Cooling Pump House provides structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Casing Cooling Pump House is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

UFSAR References

Additional details of the Casing Cooling Pump House can be found in the UFSAR, Sections 3.8.1.1.12 and 6.2.2.2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Casing Cooling Pump House are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-7, Casing Cooling Pump House.

The aging management review results for these component types are indicated in Table 3.5.2-7, Structures and Component Supports - Casing Cooling Pump House - Aging Management Evaluation.

2.4.1.8 Circulating Water Intake Tunnel Header

System Description

The Circulating Water Intake Tunnel Header is a reinforced concrete structure that parallels the Intake Structure. The tunnel header is common to both units and abuts the south side of the Intake Structure. Reinforcing bars from the tunnel header extend into the Intake Structure and tie the two structures together. The Circulating Water Intake Tunnel Header is supported on soil and steel piles.

The Circulating Water Intake Tunnel Header receives circulating water, which is discharged by the circulating water pumps located in the Intake Structure, and directs the water into the Circulating Water Intake Tunnels. Although the Circulating Water Intake Tunnel Header is nonsafety-related, the Circulating Water Intake Tunnel Header provides support for safety-related auxiliary service water lines.

System Evaluation Boundary

The evaluation boundary of the Circulating Water Intake Tunnel Header includes concrete elements associated with beams, columns, walls, slabs, and foundations; and steel piles.

System Intended Functions

The Circulating Water Intake Tunnel Header is a nonsafety-related structure whose failure could affect the function of safety-related systems, structures, and components. Therefore, the Circulating Water Intake Tunnel Header is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

UFSAR References

Additional details of the Circulating Water Intake Tunnel Header can be found in the UFSAR, Sections 3.8.1.4.3 and 10.4.2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Circulating Water Intake Tunnel Header are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-8, Circulating Water Intake Tunnel Header.

The aging management review results for these component types are indicated in Table 3.5.2-8, Structures and Component Supports - Circulating Water Intake Tunnel Header - Aging Management Evaluation.

2.4.1.9 Containment Mat Subsurface Pump Access Shaft

System Description

Each Containment has two Containment Mat Subsurface Pump Access Shafts, also known as Containment Instrument Shafts. The shafts consist of three reinforced concrete walls, and the fourth wall is the Containment exterior wall. The top of the Containment mat foundation supports each shaft. The shafts provide access and support for dewatering pumps and associated piping that are used to control Containment liner hydrostatic pressure. Access to the Unit 1 shafts and one of the Unit 2 shafts is from ground level. Access to the other Unit 2 shaft is located in the basement of the Decontamination Building.

System Evaluation Boundary

The evaluation boundary of the Containment Mat Subsurface Pump Access Shafts includes concrete elements associated with the shaft walls and hatch. The Containment exterior wall and the Containment mat foundation are evaluated with the Containment. The Containment mat subsurface pumps are evaluated with the drains-aerated system.

System Intended Functions

The Containment Mat Subsurface Pump Access Shafts provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Containment Mat Subsurface Pump Access Shafts are within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

UFSAR References

Additional details of the Containment Mat Subsurface Pump Access Shaft can be found in the UFSAR, Sections 3.8.2.1.1 and 3.8.2.1.3.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the containment mat subsurface pump access shaft.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-9, Containment Mat Subsurface Pump Access Shaft.

The aging management review results for these component types are indicated in Table 3.5.2-9, Structures and Component Supports - Containment Mat Subsurface Pump Access Shaft - Aging Management Evaluation.

2.4.1.10 Decontamination Building

System Description

The Decontamination Building is common to both units and is located adjacent to the Waste Solidification Building. The Decontamination Building is a multi-story structure that is supported by a reinforced concrete foundation on soil. The below-grade portions of the exterior walls are constructed of reinforced concrete, and the above-grade walls are constructed of steel framing with metal siding or masonry blocks. The roof for this building is a built-up roof that is supported by steel framing and metal decking.

System Evaluation Boundary

The evaluation boundary for the Decontamination Building includes aluminum elements that include louvers and screens; bolting; concrete elements associated with walls, slabs, foundation, pads, and dikes; masonry block walls; roofing membrane; and steel elements associated with beams, columns, baseplates, decking, doors, siding, and embedded steel.

System Intended Functions

Failure of the Decontamination Building structure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). Therefore, the Decontamination Building is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Decontamination Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Decontamination Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Decontamination Building can be found in the UFSAR, Section 3.8.1.1 and Table 3.2-1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Decontamination Building are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-10, Decontamination Building.

The aging management review results for these component types are indicated in Table 3.5.2-10, Structures and Component Supports - Decontamination Building - Aging Management Evaluation.

2.4.1.11 Dikes, Firewalls, and Equipment Foundations

System Description

Dikes, Firewalls, and Equipment Foundations are reinforced concrete structures located in the yard (external to buildings and structures). Firewalls have been installed around the main transformer areas, station service transformer areas, and the reserve station service transformer areas to prevent the spread of fire. The main and station service transformers are located along the north side of the Turbine Building. The reserve station service transformers are located next to the North Anna Reservoir, adjacent to the Intake Structure Control House. The transformer bays for the main and station service transformers are open on one side, with firewalls on the other three sides (i.e., firewalls are between the transformers and on the side adjacent to the Turbine Building). The transformer bays for the reserve station service transformers are open on the front and back, with firewalls between the transformers. The firewalls are attached below grade to spread footings that are soil supported. Steel structures supporting electrical cables are attached to the firewalls.

The main transformers, station service transformers, and the reserve station service transformers are surrounded by dike walls that are embedded in soil. The dike walls are sized to contain the volume of oil from a transformer, preventing the oil from spreading.

The fuel oil storage tank is surrounded by dike walls sized to contain the volume of the above-ground fuel oil storage tank. The dike walls are attached below grade to reinforced concrete spread footings founded on rock. The fuel oil storage tank is located east of the Fuel Oil Pump House.

Equipment foundations are reinforced concrete foundations for miscellaneous equipment and structures located in the yard that are within the scope of license renewal, such as foundations for the reserve station service transformers. The foundation configurations vary; however, these foundations are typically soil supported.

System Evaluation Boundary

The evaluation boundary for Dikes, Firewalls, and Equipment Foundations includes bolting; concrete elements associated with dikes, foundations, walls, and pads; and steel elements associated with beams, columns, baseplates, and embedded steel.

System Intended Functions

Dikes, Firewalls, and Equipment Foundations perform the following safety-related functions: These structures provide structural support, shelter and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, Dikes, Firewalls, and Equipment Foundations are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Dikes, Firewalls, and Equipment Foundations provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, Dikes, Firewalls, and Equipment Foundations are within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Dikes, Firewalls, and Equipment Foundations are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, Dikes, Firewalls, and Equipment Foundations are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Dikes, Firewalls, and Equipment Foundations can be found in the UFSAR, Sections 9.5.1.3.1.2 and 9.5.1.4.1.2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Dikes, Firewalls, and Equipment Foundations are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-11, Dikes, Firewalls, and Equipment Foundations.

The aging management review results for these component types are indicated in Table 3.5.2-11, Structures and Component Supports - Dikes, Firewalls, and Equipment Foundations - Aging Management Evaluation.

2.4.1.12 Discharge Tunnel & Seal Pit

System Description

Circulating water from the main condensers is directed to a reinforced concrete Discharge Tunnel via steel pipes. A separate Discharge Tunnel is provided for each unit. When backup service water is supplied from the North Anna Reservoir, the alternate supply of service water discharges to the North Anna Reservoir via the Discharge Tunnel.

The Discharge Tunnels are below grade reinforced concrete structures that are soil supported. Segments of the Discharge Tunnels run through the lower portion of the Service Building; however, in these areas the Service Building foundation and the base of the Discharge Tunnels are integral.

The Unit 2 Discharge Tunnel combines with the Unit 1 Discharge Tunnel near the Unit 1 main condenser to form a common tunnel. The two tunnels share an inner wall from this point to where the tunnels terminate at the Seal Pit. From the seal pit area, water enters the Discharge Canal, which directs the water to the Waste Heat Treatment Facility. Located on top of the Discharge Tunnels, just before the tunnels terminate at the Seal Pit, is the Vacuum Priming House.

System Evaluation Boundary

The evaluation boundary of the Discharge Tunnel and Seal Pit includes concrete elements associated with beams, walls, slabs, and foundations.

The Vacuum Priming House was determined not to be in the scope of subsequent license renewal. The Vacuum Priming House is a nonsafety-related concrete block structure that does not perform a license renewal intended function.

System Intended Functions

The Discharge Tunnel and Seal Pit perform the following safety-related functions: The structures provide a flow path for water required for reactor shutdown and the ability to maintain the reactor in a safe shutdown condition. Therefore, the Discharge Tunnel and Seal Pit are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Discharge Tunnel and Seal and Seal Pit provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Discharge Tunnel and Seal Pit are within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

UFSAR References

Additional details of the Discharge Tunnel & Seal Pit can be found in the UFSAR, Sections 1.2.5, 2.4.8, 3.8.1.4.3, 9.2.1, and 10.4.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Discharge Tunnel & Seal Pit are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-12, Discharge Tunnel & Seal Pit.

The aging management review results for these component types are indicated in Table 3.5.2-12, Structures and Component Supports - Discharge Tunnel & Seal Pit - Aging Management Evaluation.

2.4.1.13 Domestic Water Treatment Building

System Description

The Domestic Water Treatment Building is common to both units and is located in the yard north of the Unit 1 Turbine Building. The Domestic Water Treatment Building is a single-story structure that is supported by a reinforced concrete mat foundation on soil, and enclosed with masonry block walls. The roof system for the building consists of metal decking covered with a built-up roof. The Domestic Water Treatment Building houses the hydropneumatic tank and associated piping, which are within the scope of subsequent license renewal.

System Evaluation Boundary

The evaluation boundary for the Domestic Water Treatment Building includes bolting; concrete elements associated with the mat foundation; masonry block walls; roofing membrane; and steel elements associated with beams, columns, baseplates, doors; decking, and embedded steel. The hydropneumatic tank is evaluated with the fire protection system.

System Intended Functions

The Domestic Water Treatment Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Domestic Water Treatment Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Domestic Water Treatment Building can be found in the UFSAR, Section 9.5.1.2.1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Domestic Water Treatment Building are listed below:

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Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-13, Domestic Water Treatment Building.

The aging management review results for these component types are indicated in Table 3.5.2-13, Structures and Component Supports - Domestic Water Treatment Building - Aging Management Evaluation.

2.4.1.14 Duct Banks

System Description

Duct Banks are underground reinforced concrete structures used for the routing of electrical cables between plant structures. Duct Banks are configured of multiple conduits in an excavated trench that are encased in concrete and then backfilled.

Included with the evaluation of Duct Banks are reinforced concrete cable trenches. Cable trenches may be above ground or partially underground, but cable trenches have removable concrete covers to allow for access.

System Evaluation Boundary

The evaluation boundary for the Duct Banks includes concrete elements associated with duct banks and cable trenches. For duct banks and cable trenches, the evaluation boundaries terminate at the point that these structures interface with or enter separate structures (e.g., building or manhole).

System Intended Functions

Duct Banks perform the following safety-related functions: Duct Banks provide structural support, shelter and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, Duct Banks are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Duct Banks are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, the Duct Banks are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Duct Banks can be found in the UFSAR, Sections 3.8.1.1.1 and 3.8.1.1.2.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the duct banks.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-14, Duct Banks.

The aging management review results for these component types are indicated in Table 3.5.2-14, Structures and Component Supports - Duct Banks - Aging Management Evaluation.

2.4.1.15 Flood Protection Dike

System Description

An earthen Flood Protection Dike is located just west of the Unit 2 end of the Turbine Building, in the abandoned Units 3 and 4 restoration area. The dike provides protection from floodwaters resulting from a probable maximum flood.

The Flood Protection Dike is a homogeneous dike constructed with earthfill that is approximately 20 feet high, with a dike crest that is approximately 30 feet wide. The slopes of the dike are protected from erosion with vegetation and rip rap.

A steel culvert (pipe) is installed through the dike to drain the area between the dike and the Turbine Building. The steel culvert's exterior is tape wrapped and provided with cathodic protection, and the culvert's interior has a cement-mortar liner. The steel culvert has a sluice gate valve on the inlet end (i.e., Turbine Building side) and a flap valve on the discharge end of the culvert (i.e., abandoned Units 3 and 4 restoration area).

A concrete catch basin with a metal grate is installed at the inlet end of the steel drain culvert that directs rain water runoff into the steel drain culvert. At the outlet end of the steel drain culvert (i.e., flap valve location), a concrete endwall directs the runoff into a drainage ditch.

System Evaluation Boundary

The evaluation boundary of the Flood Protection Dike includes bolting; concrete elements associated with the catch basin; earthen dike and embankment; piping components associated with steel culvert; steel elements associated with the metal grate; and sluice gate valve body.

Structures and components evaluated for the Flood Protection Dike and determined not to be within the scope of subsequent license renewal are the flap valve located at the discharge end of the culvert, and concrete endwall. These structures and components do not perform a license renewal intended function and failure will not prevent the satisfactory accomplishment of a safety-related function.

System Intended Functions

The Flood Protection Dike performs the following safety-related functions: The structure provides structural support and flood protection for safety-related SSCs. Therefore, the Flood Protection Dike is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Flood Protection Dike provides structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Flood Protection Dike is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

UFSAR References

Additional details of the Flood Protection Dike can be found in the UFSAR, Sections 2.5.5 and 3.8.6; and Figure 3.8-61.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Flood Protection Dike are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-15, Flood Protection Dike.

The aging management review results for these component types are indicated in Table 3.5.2-15, Structures and Component Supports - Flood Protection Dike - Aging Management Evaluation.

2.4.1.16 Fuel Building

System Description

The Fuel Building is common to both units and is located between the two Containments. The spent fuel pool, which is also known as the spent fuel pit, and the exterior reinforced concrete walls of the Fuel Building are supported by a reinforced concrete mat foundation on rock. The substructure of the Fuel Building consists of intermediate reinforced concrete floor slabs, beams, interior walls, and masonry walls. The superstructure of the Fuel Building extends from the top of the reinforced concrete walls to the roof which is supported by structural steel framing and enclosed with metal siding. The roof is covered with metal decking and a membrane roofing system. Rolling steel and metal doors are provided for access to the Fuel Building.

The Fuel Building includes the new fuel storage area; the spent fuel pool and transfer canals; and the spent fuel storage racks.

New Fuel Storage Area

Structural steel framing members are attached to the Fuel Building's concrete floor to provide support for the new fuel storage assembly's stainless steel guide tubes.

Spent Fuel Pool and Transfer Canals

The spent fuel pool and transfer canals are reinforced concrete structures, lined inside with stainless steel plates. The liner plate is anchored to the concrete side with steel anchors, stiffeners, and other appurtenances. The liner plate is not a load-bearing structural component. The spent fuel pool liner includes a leak chase system with embedded tell-tale piping that provides a leak collection mechanism for the liner seal welds. The transfer canal gate, and spent fuel storage racks are also fabricated from stainless steel.

The spent fuel pool receives spent fuel from each Containment through fuel transfer tubes, which enter canals on the east and west ends of the Fuel Building. Each of the transfer tubes is located within a tube enclosure (including expansion joints), that is welded to embedded steel. Equipment located inside the spent fuel pool is constructed of stainless steel for corrosion resistance.

Spent Fuel Storage Racks

The spent fuel storage racks located in the spent fuel pool are high-density racks submerged in borated water. The racks are free-standing, resting on the floor support pads, and are integrally connected to embedded plates.

System Evaluation Boundary

The evaluation boundary for the Fuel Building includes bolting; concrete elements associated with beams, columns, foundation, walls, pads, and slabs; masonry block walls; roofing membrane; spent fuel pool liner plates; stainless steel elements associated with transfer canal gates, spent fuel storage racks, and new fuel storage racks; and steel elements associated with beams, columns, doors, ladders, stairs, baseplates, decking, grating, siding, and embedded steel.

The fuel transfer tubes and bellows expansion joints are evaluated with the fuel handling system.

System Intended Functions

The Fuel Building performs the following safety-related functions: The structure provides structural support, shelter and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, the Fuel Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Fuel Building provides structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Fuel Building is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Fuel Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Fuel Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Fuel Building can be found in the UFSAR, Sections 2.5, 3.7, 3.8.1, 9.1, 9.4, and 9.5; and Table 3.2-1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Fuel Building are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-16, Fuel Building.

The aging management review results for these component types are indicated in Table 3.5.2-16, Structures and Component Supports - Fuel Building - Aging Management Evaluation.

2.4.1.17 Fuel Oil Pump House

System Description

The Fuel Oil Pump House is common to both units and is located in the southwest corner of the yard. The Fuel Oil Pump House is a single-story reinforced concrete structure constructed at ground grade. The Fuel Oil Pump House consists of two pump rooms and a motor control center room. The three rooms are separated from each other by reinforced concrete walls which extend down to rock. The floor for each room is a reinforced concrete slab on compacted backfill that is not integral with the surrounding walls. Portions of the Fuel Oil Pump House walls and roof provide missile protection.

System Evaluation Boundary

The evaluation boundary for the Fuel Oil Pump House includes bolting; concrete elements associated with foundation, internal structural members, slabs, walls, pads, and roof slabs; and steel elements associated with doors, ladders, baseplates, and embedded steel.

System Intended Functions

The Fuel Oil Pump House performs the following safety-related functions: The structure provides structural support, shelter and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, the Fuel Oil Pump House is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Fuel Oil Pump House provides structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Fuel Oil Pump House is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Fuel Oil Pump House is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, the Fuel Oil Pump House is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Fuel Oil Pump House can be found in the UFSAR, Sections 3.8.1.1.10 and 9.5.1.3.1.2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Fuel Oil Pump House are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-17, Fuel Oil Pump House.

The aging management review results for these component types are indicated in Table 3.5.2-17, Structures and Component Supports - Fuel Oil Pump House - Aging Management Evaluation.

2.4.1.18 Intake Structure

System Description

The Intake Structure is located on the shore of the North Anna Reservoir and is common to both units. The Intake Structure is an eight bay (four bays serve each unit) reinforced concrete structure supported by a reinforced concrete mat foundation on soil. The Intake Structure draws water from the reservoir and provides cooling water to the main condensers, backup service water, and makeup water to the Service Water Reservoir. Each bay is separated by a reinforced concrete wall and houses one of the eight circulating water pumps. Additionally, two of the eight bays also house the lower portion of auxiliary service water pumps, and one of the bays houses the lower portion of the auxiliary motor-driven fire pump. Before entering the Intake Structure, inlet water passes through trash racks and traveling screens located at the mouth of each bay, which provide a physical barrier to debris contained in the water. Portable metal seal plates are provided to permit dewatering of the individual bays of the structure. There are two reinforced concrete wing walls on the waterside corners of the Intake Structure to direct water into the Intake Structure bays.

Located on top or deck of the Intake Structure are the Auxiliary Service Water Pump House and the Fire Pump House. The Auxiliary Service Water Pump House is a reinforced concrete structure that houses two safety-related auxiliary service water pumps and associated equipment. The Fire Pump House is a concrete block structure with a built-up roof over reinforced concrete roof slab that houses the auxiliary motor-driven fire pump and associated equipment.

On the deck of the Intake Structure, adjacent to each circulating water pump, are steel access panels. Two of these access panels are three-inch steel plates that provide missile protection to safety-related service water lines.

The Intake Structure Control House is located just west of the Intake Structure and houses electrical equipment required to operate nonsafety-related equipment at the Intake Structure, including the auxiliary motor-driven fire pump. The Intake Structure Control House is a reinforced concrete and concrete block building with a built-up roof over reinforced concrete roof slab and is supported by reinforced concrete spread footings.

System Evaluation Boundary

The evaluation boundary of the Intake Structure includes aluminum elements associated with roof access covers, louvers and screens; bolting; concrete elements associated with beams, columns, walls, slabs, curbs, pads, and foundations; masonry block walls; roofing membrane; and steel elements associated with beams, columns, baseplates, stairs, platforms, grating, decking, ladders, embedded steel, doors, louvers, screens, trash racks, and missile shields for the Intake Structure, Auxiliary Service Water Pump House, Fire Pump House, and Intake Structure Control House. The trash racks included in the evaluation boundary are the two trash racks associated with the auxiliary service water pumps and one trash rack associated with the fire pump.

Structures and components evaluated for the Intake Structure and determined not to be within the scope of subsequent license renewal are the five trash racks that are associated only with the circulating water system, and portable metal seal plates. These structures and components do not perform a license renewal intended function and their failure will not prevent the satisfactory accomplishment of a safety-related function.

The traveling screens are active components and do not require aging management.

System Intended Functions

The Intake Structure performs the following safety-related functions: The structure provides structural support, shelter and protection for safety-related SSCs; and a flowpath for water required to provide the capability to shut down the reactor and maintain it in a safe shutdown condition. Therefore, the Intake Structure is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Intake Structure provides structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Intake Structure is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Intake Structure is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, the Intake Structure is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Intake Structure can be found in the UFSAR, Sections 3.8.1.1.9, 9.2.1, and 10.4.2; and Table 3.2-1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Intake Structure are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-18, Intake Structure.

The aging management review results for these component types are indicated in Table 3.5.2-18, Structures and Component Supports - Intake Structure - Aging Management Evaluation.

2.4.1.19 Main Steam Valve House

System Description

A Main Steam Valve House is provided for each unit and each is located adjacent to the Containment and Quench Spray Pump House for its respective unit. Each Main Steam Valve House is a multi-story reinforced concrete structure with a mat foundation that is a common foundation with the Quench Spray Pump House. The Unit 1 foundation is supported by concrete backfill on rock. The Unit 2 foundation is supported by compacted soil. The exterior walls and roof are heavy reinforced concrete structures designed to resist missiles. Intermediate floors are reinforced concrete slabs or grating/decking supported by structural steel framing. Roof openings with concrete hatches are provided for the removal of equipment. These openings and concrete hatches are enclosed by a steel cover plate that is supported on steel members.

System Evaluation Boundary

The evaluation boundary for the Main Steam Valve House includes bolting; concrete elements associated with beams, columns, foundation, walls, pads, hatches, and roof slabs; masonry block walls; and steel elements associated with beams, columns, doors, stairs, baseplates, decking, grating, and embedded steel.

System Intended Functions

The Main Steam Valve House performs the following safety-related functions: The structure provides structural support, shelter and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, the Main Steam Valve House is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Main Steam Valve House provides structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Main Steam Valve House is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Main Steam Valve House is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the Main Steam Valve House is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Main Steam Valve House can be found in the UFSAR, Sections 3.8.1.1.1 and 9.5.1.3.1.10.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Main Steam Valve House are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-19, Main Steam Valve House.

The aging management review results for these component types are indicated in Table 3.5.2-19, Structures and Component Supports - Main Steam Valve House - Aging Management Evaluation.

2.4.1.20 Maintenance Building

System Description

The Maintenance Building, also known as the Machine Shop Building, is common to both units and is located east of the Unit 1 Auxiliary Feedwater Pump House. The Maintenance Building is a multi-story structure that is enclosed with metal siding and a built-up roof on metal decking. Intermediate floors are constructed of reinforced concrete and are supported by steel framing. The structure is founded on reinforced concrete piers on rock, and grade beams.

System Evaluation Boundary

The evaluation boundary for the Maintenance Building includes bolting; concrete elements associated with walls, slabs, and foundation; masonry block walls; roofing membrane; and steel elements associated with beams, columns, baseplates, grating, decking, doors, and embedded steel.

System Intended Functions

The Maintenance Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Maintenance Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Maintenance Building can be found in the UFSAR, Section 9.5.1.2.1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Maintenance Building are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-20, Maintenance Building.

The aging management review results for these component types are indicated in Table 3.5.2-20, Structures and Component Supports - Maintenance Building - Aging Management Evaluation.

2.4.1.21 Manholes

System Description

Manholes are reinforced concrete structures buried underground that are supported on soil. Manhole access openings, which allow personnel access, occur approximately at grade level. Safety-related Manhole openings are protected with steel manway missile barrier covers.

System Evaluation Boundary

The evaluation boundary for the Manholes includes bolting; concrete elements associated with manhole structures; and steel elements associated with manhole covers and ladders.

System Intended Functions

Manholes perform the following safety-related functions: Manholes provide structural support, shelter and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, Manholes are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Manholes provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, Manholes are within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Manholes are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, Manholes are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

None

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the manholes.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-21, Manholes.

The aging management review results for these component types are indicated in Table 3.5.2-21, Structures and Component Supports - Manholes - Aging Management Evaluation.

2.4.1.22 New Fuel Receiving Building

System Description

The New Fuel Receiving Building is common to both units and is located south of the Fuel Building. The New Fuel Receiving Building is a single-story structure that is supported by reinforced concrete footings founded on rock. The building is enclosed by a steel framed structure with metal siding, and a built-up roof that is supported by steel framing and metal decking.

System Evaluation Boundary

The evaluation boundary for the New Fuel Receiving Building includes aluminum elements that include louvers and screens; bolting; concrete elements associated with foundation, walls, and slabs; roofing membrane; and steel elements associated with beams, columns, baseplates, decking, siding, doors, and embedded steel.

System Intended Functions

Failure of the New Fuel Receiving Building structure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). Therefore, the New Fuel Receiving Building is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The New Fuel Receiving Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the New Fuel Receiving Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the New Fuel Receiving Building can be found in the UFSAR, Sections 3.8.1.1.4, 9.1.1, and 9.5.1.2.3.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the New Fuel Receiving Building are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-22, New Fuel Receiving Building.

The aging management review results for these component types are indicated in Table 3.5.2-22, Structures and Component Supports - New Fuel Receiving Building - Aging Management Evaluation.

2.4.1.23 Quench Spray Pump House

System Description

A Quench Spray Pump House is provided for each unit and each is located adjacent to the Containment and Main Steam Valve House for its respective unit. Each Quench Spray Pump House is a reinforced concrete structure with a mat foundation that is a common foundation with the Main Steam Valve House. The Unit 1 foundation is supported by concrete backfill, which extends down to rock. The Unit 2 foundation is supported by compacted soil. The Quench Spray Pump House is a two-story structure and the lower story is below grade. It has a built-up metal deck roof and an intermediate concrete floor slab.

System Evaluation Boundary

The evaluation boundary for the Quench Spray Pump House includes aluminum elements that include louvers and screens; bolting; concrete elements associated with beams, columns, foundation, walls, pads, and slabs; roofing membrane; and steel elements associated with beams, columns, doors, ladders, stairs, baseplates, decking, grating, and embedded steel.

System Intended Functions

The Quench Spray Pump House performs the following safety-related functions: The structure provides structural support, shelter and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, the Quench Spray Pump House is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Quench Spray Pump House provides structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Quench Spray Pump House is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Quench Spray Pump House is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, the Quench Spray Pump House is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Quench Spray Pump House can be found in the UFSAR, Sections 3.8.1.1.1 and 9.5.1.3.1.11.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Quench Spray Pump House are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-23, Quench Spray Pump House.

The aging management review results for these component types are indicated in Table 3.5.2-23, Structures and Component Supports - Quench Spray Pump House - Aging Management Evaluation.

2.4.1.24 Safeguards Building

System Description

A Safeguards Building is provided for each unit and each building is located adjacent to the Containment and Quench Spray Pump House of its respective unit. Each Safeguards Building is a reinforced concrete structure that houses safeguards equipment including the outside recirculating spray pumps, and the low-head safety injection pumps. It is a partially below grade, two-story building with a mat foundation supported by rock. The building has three external side walls of reinforced concrete; the fourth side wall is the Containment exterior wall. The exterior walls and roof are heavy reinforced concrete structures designed to resist missiles. Openings in the walls and roof are protected with concrete or steel missile shields.

System Evaluation Boundary

The evaluation boundary for the Safeguards Building includes bolting; concrete elements associated with foundation, internal structural members, walls, pads, hatches, and roof slabs; and steel elements associated with doors, ladders, stairs, beams, missile shields, baseplates, grating, and embedded steel.

System Intended Functions

The Safeguards Building performs the following safety-related functions: The structure provides structural support, shelter and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, the Safeguards Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Safeguards Building provides structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Safeguards Building is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Safeguards Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Safeguards Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Safeguards Building can be found in the UFSAR, Sections 3.8.1.1.1 and 9.3.3.2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Safeguards Building are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-24, Safeguards Building.

The aging management review results for these component types are indicated in Table 3.5.2-24, Structures and Component Supports - Safeguards Building - Aging Management Evaluation.

2.4.1.25 SBO Building

System Description

The SBO Building, also known as the AAC Building, is common to both units and is located west of the Turbine Building. The SBO Building is a single-story structure that is enclosed with concrete walls and metal siding. The roof is constructed of metal decking covered with a built-up roof, and the structure is founded on reinforced concrete piers and spread footings supported by soil. The SBO Building houses the alternate diesel generator and its associated auxiliaries, which provide alternate power to the safe shutdown equipment in the event of a station blackout.

System Evaluation Boundary

The evaluation boundary for the SBO Building includes aluminum elements that include louvers and screens; bolting; concrete elements associated with foundation, walls, pads, dikes, and slabs; masonry block walls; roofing membrane; and steel elements associated with beams, columns, doors, siding, platforms, baseplates, grating, louvers, screens, and embedded steel.

System Intended Functions

The SBO Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, the SBO Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the SBO Building can be found in the UFSAR, Section 9.5.11.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the SBO Building are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-25, SBO Building.

The aging management review results for these component types are indicated in Table 3.5.2-25, Structures and Component Supports - SBO Building - Aging Management Evaluation.

2.4.1.26 SBO Structures for Offsite Power

System Description

Offsite power supplies relied upon to recover from a station blackout originate at the 34.5 kV circuit breakers and associated disconnect switches located in the switchyard. The 34.5 kV breakers and disconnect switches are supported by reinforced concrete foundations and steel support structures. Controls for the 34.5 kV breakers are contained in an adjacent 500 kV control house. The 500 kV control house is a one-story, steel framed structure with metal siding. The building is supported by a concrete slab on grade, and the roof system consists of metal decking covered with a built-up roof. The control cables from the 500 kV control house to the 34.5 kV circuit breakers are routed in concrete cable trenches.

Electrical distribution system cables from the 34.5 kV circuit breakers in the switchyard to the reserve station service transformers are routed in cable trenches, manholes, and duct banks. In addition, there are two 34.5 kV overhead lines, available as backup in case of failure or maintenance of an underground cable, that route from the 34.5 kV circuit breakers in the switchyard to the reserve station service transformers. These overhead lines are supported by steel poles with concrete foundations. The reserve station service transformers are supported by reinforced concrete foundations, which are surrounded by a reinforced concrete dike, and separated by reinforced concrete walls (firewalls). The electrical distribution system cables in this area are supported by steel support structures that are attached to the concrete walls adjacent to the transformers or from concrete foundations.

From the reserve station service transformers, the electrical distribution system cables are routed in duct banks and manholes to the Turbine Building and the Intake Structure Control House. A separate circuit from the reserve station service transformers to the Turbine Building is routed via overhead tubular bus supported by steel or concrete poles. These poles were originally precast concrete poles, but there is a design change currently being implemented that either replaces or refurbishes these poles. Most of the existing precast concrete poles are being replaced with galvanized steel poles. The poles adjacent to the Turbine Building will remain as precast concrete, but these poles will be externally reinforced with a carbon fiber reinforced polymer (CFRP) wrap. Most of the poles have been replaced or reinforced with a CFRP wrap.

System Evaluation Boundary

The evaluation boundary for the SBO Structures for Offsite Power includes the structures that support and/or protect the electrical distribution system (e.g., cables, breakers, and switches) associated with the offsite SBO recovery path from the switchyard, except as noted below, through the RSSTs, and up to building interfaces. The evaluation boundary for the SBO Structures for Offsite Power includes bolting; concrete elements associated with foundations, walls, pads, poles (including poles wrapped with CFRP), and slabs; roofing membrane; and steel elements associated with beams, columns, doors, siding, baseplates, decking, poles, and embedded steel.

Structures not included in the evaluation boundary of the SBO Structures for Offsite Power are duct banks, trenches, manholes, transformer fire walls, and dikes. These structures are evaluated in their respective structural sections along with other similar structural components.

The Turbine Building, Intake Structure Control House, and Service Building are evaluated separately.

System Intended Functions

SBO Structures for Offsite Power are relied upon for compliance with regulations for Station Blackout (10 CFR 50.63). Therefore, the SBO Structures for Offsite Power are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the SBO Structures for Offsite Power can be found in the UFSAR, Section 8.1.2.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the SBO Structures for Offsite Power are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-26, SBO Structures for Offsite Power.

The aging management review results for these component types are indicated in Table 3.5.2-26, Structures and Component Supports - SBO Structures for Offsite Power - Aging Management Evaluation.

2.4.1.27 Security Diesel Building

System Description

The Security Diesel Building is common to both units and is located south of the Maintenance Building. The Security Diesel Building is a single-story structure that is enclosed by concrete walls and roof. The structure is founded on a reinforced concrete mat foundation and spread footings.

System Evaluation Boundary

The evaluation boundary for the Security Diesel Building includes bolting; concrete elements associated with beams, columns, walls, slabs, foundation, and pads; and steel elements associated with beams, columns, doors, baseplates, and embedded steel.

System Intended Functions

The Security Diesel Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Security Diesel Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

None

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Security Diesel Building are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-27, Security Diesel Building.

The aging management review results for these component types are indicated in Table 3.5.2-27, Structures and Component Supports - Security Diesel Building - Aging Management Evaluation.

2.4.1.28 Security Lighting Poles

System Description

Operator access routes to various components that are required for an Appendix R safe shutdown may require travel through the yard area to other buildings or structures. Backup lighting for these exterior routes are provided by the station security perimeter lighting system. Steel poles located inside and along the perimeter fence support security lighting that provides the required illumination for operator access to various components in other buildings or structures in the yard area. The Security Lighting Poles are constructed of galvanized steel that are welded to baseplates. Anchor bolts attach the baseplates to reinforced concrete foundations.

System Evaluation Boundary

The evaluation boundary for the Security Lighting Poles includes bolting; concrete elements associated with pole foundations; and steel elements associated with poles and baseplates.

System Intended Functions

Security Lighting Poles are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Security Lighting Poles are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Security Lighting Poles can be found in the UFSAR, Section 9.5.3.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Security Lighting Poles are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-28, Security Lighting Poles.

The aging management review results for these component types are indicated in Table 3.5.2-28, Structures and Component Supports - Security Lighting Poles - Aging Management Evaluation.

2.4.1.29 Service Building

System Description

The Service Building is common to both units and is adjacent to the Auxiliary Building and Turbine Building. The Service Building is founded on reinforced concrete mat, strip, spread footings; and grade beams. The varying foundation elements are partially on rock and partially on soil. The flooring consists of slabs on grade and intermediate floors. Structural floor slabs are cast on permanent metal deck forms supported by structural steel framing. The roof is constructed of metal decking covered with built-up roofing. Reinforced concrete walls surround the cubicles requiring tornado missile protection. Substructure walls are constructed of reinforced concrete or masonry blocks. Flood protection barriers, fire and EQ doors, fire barriers, including penetration seals, are provided to protect safety-related equipment.

The Service Building is a multi-story structure and includes the following rooms or cubicles: normal and emergency switchgear and relay rooms; battery rooms; mechanical equipment rooms; cable tunnels; main control room; stairwell; technical support center; chiller rooms; emergency diesel generator rooms; cable tray rooms; auxiliary heater boiler room; and warehouse. The emergency switchgear and relay rooms, battery rooms, emergency diesel generator rooms, chiller rooms, main control room, cable tunnels, and the mechanical equipment rooms house safety-related components. The other rooms or cubicles house components relied upon for compliance with regulated events.

System Evaluation Boundary

The evaluation boundary for the Service Building includes aluminum elements that include louvers and screens; bolting; concrete elements associated with beams, columns, foundation, walls, pads, curbs, and slabs; doors; masonry block walls; roofing membrane; and steel elements associated with beams, columns, ladders, stairs, baseplates, decking, grating, siding, dikes, and embedded steel.

System Intended Functions

The Service Building performs the following safety-related functions: The structure provides structural support, shelter and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, the Service Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Service Building provides structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Service Building is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Service Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the Service Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Service Building can be found in the UFSAR, Sections 3.1.15, 3.3.2, 3.8.1, 3.8.5, 9.4, and 9.5.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Service Building are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-29, Service Building.

The aging management review results for these component types are indicated in Table 3.5.2-29, Structures and Component Supports - Service Building - Aging Management Evaluation.

2.4.1.30 Service Water Pump House

System Description

The Service Water Pump House is a reinforced concrete structure located at the edge of the Service Water Reservoir and is common to both units. The Service Water Pump House primarily houses service water system piping and equipment. The Service Water Pump House is supported by a reinforced concrete mat foundation on soil. The lower level of the structure has four bays. Each bay is separated by a reinforced concrete wall and houses one of the four service water pumps. Before entering the structure, inlet water passes through trash racks and traveling screens located at the entrance of each bay, which provide a physical barrier to debris contained in the water. There are reinforced concrete wing walls on the waterside corners of the structure to direct water into the bays. The structure has missile-protected concrete roof openings.

System Evaluation Boundary

The evaluation boundary for the Service Water Pump House includes bolting; concrete elements associated with beams, columns, walls, slabs, foundation, and pads; and steel elements associated with doors, ladders, stairs, beams, missile shields, baseplates, grating, trash racks, and embedded steel.

The traveling screens are active components and are not subject to aging management review.

System Intended Functions

The Service Water Pump House performs the following safety-related functions: The structure provides structural support, shelter and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, the Service Water Pump House is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Service Water Pump House provides structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Service Water Pump House is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Service Water Pump House is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, the Service Water Pump House is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Service Water Pump House can be found in the UFSAR, Section 3.8.1.1.7 and Appendix 3E.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the service water pump house.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-30, Service Water Pump House.

The aging management review results for these component types are indicated in Table 3.5.2-30, Structures and Component Supports - Service Water Pump House - Aging Management Evaluation.

2.4.1.31 Service Water Reservoir

System Description

The Service Water Reservoir is an earthen structure located south of the station and is more than 40 feet above plant grade. The Service Water Reservoir is the primary source of cooling water for plant shutdown. The Service Water Reservoir is also a source of fire suppression water. A diesel engine driven pump, located in the Service Water Pump House, takes suction from the Service Water Reservoir and supplies the yard hydrant piping loop.

The Service Water Reservoir was constructed by diking an area between two adjacent gullies and excavating from the area behind the dikes to provide the required volume of emergency cooling water. The bottom of the reservoir was lined with a two-foot thick layer of compacted soil having a high clay content and very low permeability. The compacted clay liner extends up the inside slope of the dike to above the maximum water level. The clay liner is protected against erosion with a layer of dumped rockfill.

On the exterior slope of the dike core is a transition filter zone of a fine and coarse filter, which provides internal drainage and forms a transition zone between the impervious core and the compacted rockfill on the exterior portion of the dike. The rockfill extends across the crest of the dike and completely covers the exterior slope. The rockfill across the crest is covered with a coarse aggregate to form a roadway surface.

A reinforced concrete apron is installed around the intake to the Service Water Pump House and adjacent to the Service Water Valve House to prevent erosion of the liner from flowing water.

The Service Water Reservoir embankment is separated from the main plant structures by an emergency dike and intercepting channel. The channel provides additional conservatism for flood protection of the station in the event of a failure of the Service Water Reservoir embankment.

A spray piping system is installed in the Service Water Reservoir to dissipate heat from the service water. The Service Water Reservoir spray piping system is supported by braced steel frames with reinforced concrete foundations that are installed on the Service Water Reservoir clay liner. An underwater bypass system is installed for winter operation.

System Evaluation Boundary

The evaluation boundary of the Service Water Reservoir includes concrete elements associated with the concrete aprons adjacent to the Service Water Pump House and Service Water Valve House, and the concrete foundations for the spray piping supports; and earthen dike and embankment.

The service water system spray piping is evaluated in the service water system mechanical section; and the associated pipe supports and braced steel frames are evaluated in the Component Supports structural section.

The emergency dike and channel is a nonsafety-related structure whose failure will not affect the safety-related function of the Service Water Reservoir and is not in the scope of subsequent license renewal.

System Intended Functions

The Service Water Reservoir performs the following safety-related functions: The structure provides structural support for safety-related SSCs and provides a barrier to contain water inventory for plant shutdown. Therefore, the Service Water Reservoir is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Service Water Reservoir is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, the Service Water Reservoir is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Service Water Reservoir can be found in the UFSAR, Sections 2.4, 2.5.5, 3.8.1, 3.8.4; and Appendix 3E.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the service water reservoir.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-31, Service Water Reservoir.

The aging management review results for these component types are indicated in Table 3.5.2-31, Structures and Component Supports - Service Water Reservoir - Aging Management Evaluation.

2.4.1.32 Service Water Valve House

System Description

The Service Water Valve House is a reinforced concrete structure located at the northwest edge of the Service Water Reservoir and is common to both units. The Service Water Valve House is supported by a concrete mat foundation on soil and is enclosed with concrete walls and roof. The structure has missile-protected concrete roof openings.

System Evaluation Boundary

The evaluation boundary for the Service Water Valve House includes bolting; concrete elements associated with beams, columns, walls, slabs, foundation, and pads; and steel elements associated with doors, ladders, stairs, beams, missile shields, baseplates, grating, and embedded steel.

System Intended Functions

The Service Water Valve House performs the following safety-related functions: The structure provides structural support, shelter and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, the Service Water Valve House is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Service Water Valve House provides structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Service Water Valve House is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Service Water Valve House is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, the Service Water Valve House is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Service Water Valve House can be found in the UFSAR, Sections 3.8.1.1.13, 3.8.4.5.3, and 9.2.1.2.4.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the service water valve house.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-32, Service Water Valve House.

The aging management review results for these component types are indicated in Table 3.5.2-32, Structures and Component Supports - Service Water Valve House - Aging Management Evaluation.

2.4.1.33 Tank Foundations and Missile Barriers

System Description

Tank Foundations and Missile Barriers are reinforced concrete structures associated with tanks located in the yard (external to buildings and structures). The following structures are subject to aging management review:

<u>Buried Fuel Oil Tank Missile Barrier</u>

Two underground fuel oil tanks supply fuel oil to three emergency diesel generators. A soil-supported reinforced concrete missile barrier protects the two tanks. The Buried Fuel Oil Tank Missile Barrier is located between the above-ground fuel oil storage tank and the Fuel Oil Pump House.

Carbon Dioxide Tank Foundation

A carbon dioxide tank is located just north of the Turbine Building between the Unit 1 and Unit 2 station transformer bays. The tank foundation is a reinforced concrete mat, supported on soil.

Casing Cooling Tank Foundation

The Casing Cooling Tank Foundation is a reinforced concrete mat, which is a common foundation with the Casing Cooling Pump House foundation. A casing cooling tank is provided for each unit and each tank mat foundation is supported on concrete backfill, which extends down to underlying rock. Anchor bolts attach the tank to the foundation. There is a layer of grout under the attachment plates for the anchor bolts. There is an oiled-sand cushion between the tank and the mat, and caulk is used to contain the oiled-sand material under the tanks.

Chemical Addition Tank Foundation

The Chemical Addition Tank Foundation is a reinforced concrete mat that is supported on rock. A chemical addition tank is provided for each unit and each tank is located north of the Auxiliary Feedwater Pump House for its respective unit. Anchor bolts attach the tank to the foundation. There is a layer of grout under the tank skirt.

Emergency Condensate Storage Tank Foundation and Missile Barrier

The Emergency Condensate Storage Tank Foundation is a reinforced concrete mat that is supported on rock. An emergency condensate storage tank is provided for each unit and each tank is located south of the Auxiliary Feedwater Pump House for its respective unit. A reinforced concrete missile barrier completely encapsulates the tank. The missile barrier consists of reinforced concrete walls, which are integral to the mat foundation, and a dome-shaped reinforced concrete roof. There is a gap between the tank and the missile barrier, which is filled with a compressible seal material. The dome-shaped roof has openings for access and ventilation, which are covered protected by missile barriers fabricated from carbon and stainless steel.

Fuel Oil Line Missile Barrier

Fuel oil lines are routed from the Fuel Oil Pump House to the emergency diesel generator rooms located in the Service Building. Where practicable, the fuel oil lines are buried sufficiently deep that the covering soil provides an adequate missile barrier. However, adjacent to the Fuel Oil Pump House and the Service Building, the lines are buried in soil, but are also protected by stainless steel plates and pavement.

Refueling Water Storage Tank Foundation

The Refueling Water Storage Tank Foundation is a reinforced concrete mat that is supported on rock. A refueling water storage tank is provided for each unit and each tank is located north of the Auxiliary Feedwater Pump House for its respective unit. Anchor bolts attach the tank to the foundation. There is a layer of grout under the attachment plates for the anchor bolts. There is an oiled-sand cushion between the tank and the mat, and caulk is used to contain the oiled-sand material under the tanks.

System Evaluation Boundary

The evaluation boundary for the Tank Foundations and Missile Barriers includes bolting; caulking and sealants; compressible seal material; concrete elements associated with foundation, hatches, and missile barriers; grout; stainless steel elements associated with missile barriers; and steel elements associated with baseplates, missile barriers, and embedded steel.

System Intended Functions

Tank Foundations and Missile Barriers perform the following safety-related functions: These structures provide structural support, shelter and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, Tank Foundations and Missile Barriers are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Tank Foundations and Missile Barriers provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, Tank Foundations and Missile Barriers are within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Tank Foundations and Missile Barriers are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, Tank Foundations and Missile Barriers are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Tank Foundations and Missile Barriers can be found in the UFSAR, Sections 3.8.1.1.12, 6.2.2.2, 7.3.1.3, 9.2.4, 9.5.1.3, and 9.5.4; Tables 2.4-7, 3.2-1 and 3.7-5; and Figure 9.5-4.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Tank Foundations and Missile Barriers are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-33, Tank Foundations and Missile Barriers.

The aging management review results for these component types are indicated in Table 3.5.2-33, Structures and Component Supports - Tank Foundations and Missile Barriers - Aging Management Evaluation.

2.4.1.34 Turbine Building

System Description

The Turbine Building is common to both units and is located west of the Administration Building, and north of the Service Building. The Turbine Building is a multi-story structure and the south side of the Turbine Building shares a common wall with a portion of the Service Building. The portion of the Turbine Building that is adjacent to the main control room has been designed for tornado wind load to prevent its collapse on the main control room.

The Turbine Building is constructed with a reinforced-concrete substructure and a steel framing superstructure. The substructure consists of below-grade reinforced-concrete walls and soil founded spread footings. The above-grade superstructure is a structural steel building enclosed with metal siding. The roof is made of metal decking covered with a membrane roofing system. Substructure walls are constructed of reinforced concrete or masonry blocks. Flood protection barriers, fire and EQ doors, fire barriers, including penetration seals, are provided to protect safety-related equipment.

System Evaluation Boundary

The evaluation boundary for the Turbine Building includes aluminum elements that include louvers and screens; bolting; concrete elements associated with beams, columns, foundation, walls, pads, and slabs; doors; masonry block walls; roofing membrane; and steel elements associated with beams, columns, ladders, stairs, baseplates, decking, grating, siding, dikes, and embedded steel.

System Intended Functions

The Turbine Building performs the following safety-related functions: The structure provides structural support, shelter and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, the Turbine Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

The Turbine Building provides structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, the Turbine Building is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Turbine Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the Turbine Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Turbine Building can be found in the UFSAR, Sections 2.4, 3.3.2, 3.8.1.1.11, 9.4, and 9.5.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Turbine Building are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-34, Turbine Building.

The aging management review results for these component types are indicated in Table 3.5.2-34, Structures and Component Supports - Turbine Building - Aging Management Evaluation.

2.4.1.35 Vaults, Enclosures, and Pits

System Description

Vaults, Enclosures, and Pits are reinforced concrete structures that are partially or completely below grade. The following structures are included in the evaluation:

- Auxiliary Service Water Expansion Joint Enclosure
- Service Water Pipe Expansion Joint Enclosure
- Service Water Tie-In Vault
- Yard Valve Pit

The Auxiliary Service Water Expansion Joint Enclosure is adjacent to the intake structure. The Yard Valve Pit is south of the Auxiliary Service Water Expansion Joint Enclosure. The Service Water Pipe Expansion Joint Enclosure is adjacent to the Service Water Pump House. The Service Water Tie-In Vault located north of the Service Water Reservoir.

Vaults, Enclosures, and Pits house safety-related piping and components, and the structures provide missile protection for the enclosed components. Steel manhole covers or concrete hatches are provided in the roof of these structures for personnel access and equipment installation/removal. The manhole covers and concrete hatches are also designed to resist missiles.

These structures are supported by concrete mat foundations on soil, except for the Service Water Pipe Expansion Joint Enclosure foundation. The floor for the Service Water Pipe Expansion Joint Enclosure is a slab on grade, and the adjacent walls are supported by spread footings. The Service Water Pipe Expansion Joint Enclosure is also founded on soil.

System Evaluation Boundary

The evaluation boundary for Vaults, Enclosures, and Pits includes bolting; concrete elements associated with foundation, walls, beams, hatches, and roof slabs; and steel elements associated with manhole covers, platforms, ladders, baseplates, and embedded steel.

System Intended Functions

Vaults, Enclosures, and Pits perform the following safety-related functions: These structures provide structural support, shelter and protection for safety-related SSCs required to mitigate the consequences of events that could result in potential offsite exposure. Therefore, Vaults, Enclosures, and Pits are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Vaults, Enclosures, and Pits provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, Vaults, Enclosures, and Pits are within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Vaults, Enclosures, and Pits are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, Vaults, Enclosures, and Pits are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Vaults, Enclosures, and Pits can be found in the UFSAR, Sections 3.8.1, 3.8.4.5.3, 9.2.1, and 18.1.2; Tables 2.5-1 and 3.2-1.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Vaults, Enclosures, and Pits are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-35, Vaults, Enclosures, and Pits.

The aging management review results for these component types are indicated in Table 3.5.2-35, Structures and Component Supports - Vaults, Enclosures, and Pits - Aging Management Evaluation.

2.4.1.36 Waste Disposal Building

System Description

The Waste Disposal Building is common to both units and is located in the south yard adjacent to the Boron Recovery Building. The Waste Disposal Building is a single-story structure that is supported by reinforced concrete grade beams and mat foundation on rock. The building is enclosed by a steel framed structure with metal siding, and a built-up roof that is supported by steel framing and metal decking.

System Evaluation Boundary

The evaluation boundary for the Waste Disposal Building includes aluminum elements that include louvers and screens; bolting; concrete elements associated with slabs, curbs, and foundations; roofing membrane; and steel elements associated with beams, columns, baseplates, grating, decking, doors, siding, and embedded steel.

System Intended Functions

The Waste Disposal Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Waste Disposal Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Waste Disposal Building can be found in the UFSAR, Sections 1.2.5, 9.5.1.2.3, and 12.1.3.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Waste Disposal Building are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-36, Waste Disposal Building.

The aging management review results for these component types are indicated in Table 3.5.2-36, Structures and Component Supports - Waste Disposal Building - Aging Management Evaluation.

2.4.1.37 Waste Solidification Building

System Description

The Waste Solidification Building is common to both units and is located south of the Fuel Building, adjacent to the Decontamination Building. The Waste Solidification Building is a single-story structure that is supported by reinforced concrete foundation on compacted soil. The building is enclosed by reinforced concrete walls and a built-up roof that is supported by steel framing and metal decking. The upper portions of the walls are protected by metal siding.

System Evaluation Boundary

The evaluation boundary for the Waste Solidification Building includes aluminum elements that include louvers and screens; bolting; concrete elements associated with walls, slabs, curbs, and foundations; roofing membrane; and steel elements associated with beams, columns, baseplates, siding, decking, doors, and embedded steel.

System Intended Functions

Failure of the Waste Solidification Building structure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). Therefore, the Waste Solidification Building is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

The Waste Solidification Building is relied upon for compliance with regulations for Fire Protection (10 CFR 50.48). Therefore, the Waste Solidification Building is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Waste Solidification Building can be found in the UFSAR, Section 9.4.3.

Subsequent License Renewal Boundary Drawings

The subsequent license renewal boundary drawings for the Waste Solidification Building are listed below:

11715-SLRY-001 Sh. 1

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-37, Waste Solidification Building.

The aging management review results for these component types are indicated in Table 3.5.2-37, Structures and Component Supports - Waste Solidification Building - Aging Management Evaluation.

2.4.1.38 Component Supports

System Description

Component Supports for mechanical and electrical components are an integral part of plant systems. The majority of these supports are not uniquely identified; however, Component Supports exhibit similar characteristics such as design, materials of construction, environments, and aging. Therefore, Component Supports for mechanical and electrical components are evaluated as plant structural commodities.

The commodity evaluation applies to the supports for mechanical and electrical components within the buildings and structures that are within the scope of subsequent license renewal. The supports subject to aging management review that are addressed in this section include supports and anchorage for the following:

- ASME Class 2 and Class 3 piping and components
- Cable trays, conduit, HVAC ducts, tube tracks, instrument tubing, and non-ASME Code piping and components
- Racks, panels, cabinets, and enclosures for electrical equipment and instrumentation
- Emergency diesel generator and HVAC system components, and other miscellaneous mechanical equipment
- Platforms, pipe whip restraints, jet impingement shields, masonry walls, and other miscellaneous structures

In addition, cable trays, conduits, instrument racks, and structural frames are addressed in this section.

Some piping and equipment is restrained or supported to prevent interaction with safety-related SSCs. This piping and equipment may not be included within the scope of subsequent license renewal, but the structural supports for the piping and equipment are included in-scope and are subject to aging management review.

System Evaluation Boundary

The evaluation boundary for Component Supports includes supports for mechanical and electrical components that are within the scope of subsequent license renewal, and for mechanical and electrical components that are not within the scope of subsequent license renewal, but are located such that their failure could adversely impact the performance of a safety-related SSC intended function. Component Supports include aluminum elements associated with support members, cable trays, and conduits; bolting; grout; sliding surfaces; spring hangers; guides; stops; stainless steel elements associated with support members; steel elements associated with support members, bearing plates, baseplates, connections, cable trays, conduits, instrument racks, and structural frames; and vibration isolation elements.

The evaluation boundary for Component Supports lies between the equipment or component being supported and the building supporting structure (concrete or structural steel). The portions of steel anchors embedded in concrete are evaluated with the building structure. Integral attachments and welds to pressure retaining components are addressed with the specific component in other sections.

Component Supports for ASME Class 1 piping and components, including NSSS equipment, are evaluated with NSSS Supports. Steel elements, such as beams, columns, baseplates, bracing, stairs, platforms, grating, decking, and ladders are evaluated with the applicable buildings and structures that are within the scope of subsequent license renewal.

System Intended Functions

Component Supports perform the following safety-related functions: Component Supports provide structural support, shelter and protection for safety-related SSCs. Therefore, Component Supports are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Component Supports provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, Component Supports are within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Component Supports are relied upon for compliance with regulations for: Fire Protection (10 CFR 50.48), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, Component Supports are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Component Supports can be found in the UFSAR, Sections 3.7.3 and 3.10.2; and Table 3.2-1.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the component supports.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-38, Component Supports.

The aging management review results for these component types are indicated in Table 3.5.2-38, Structures and Component Supports - Component Supports - Aging Management Evaluation.

2.4.1.39 Miscellaneous Structural Commodities

System Description

The buildings and structures within the scope of subsequent license renewal contain Miscellaneous Structural Commodities that are within the scope of subsequent license renewal and are subject to aging management review.

Listed below are the Miscellaneous Structural Commodities that have been identified as being within the scope of subsequent license renewal and subject to aging management review:

- Fireproofing and fire barriers
- Electrical enclosures
- Penetration sleeves and seals
- Seismic gap filler material and covers

Fireproofing and fire barriers are assemblies, which are designed and constructed to achieve specific fire resistance ratings, limit the spread of heat and fire, and restrict the movement of smoke.

Electrical enclosures include bus duct and switchgear enclosures, electrical panels and cabinets, junction, terminal, and pull boxes. The electrical panels and cabinets contain supports for electrical components located inside the enclosure. Gaskets provide a leak-tight condition from weather for the junction, terminal, and pull boxes. Electrical enclosures also include panels that are designed to contain potential internal fluid leakage.

Penetration sleeves are located in openings of walls, floors, roofs, or ceilings and allow components such as piping, conduits, duct banks, and tubing to be routed through the opening. Penetration seals are materials that are used to seal the penetration.

Seismic gaps (rattlespaces) are provided between adjacent structures to allow for relative motion between the structures. Although there are different configurations, the seismic gaps are arranged to prevent material from entering the gap space since the intrusion of foreign materials may impede the relative motion of adjacent structures. In most configurations, the seismic gaps are covered by structural angles or other elements such as elastomer seals, and the seismic gaps are filled with a compressible material. At certain locations the seismic covers function as fire barriers.

System Evaluation Boundary

The evaluation boundary for Miscellaneous Structural Commodities includes bolting, electrical enclosures, fireproofing, fire barriers, penetration seals, penetration sleeves, seismic gap covers, and seismic gap filler material that are located in buildings and structures that are within the scope of subsequent license renewal.

Fire damper assemblies are evaluated in the fire protection system. Fire barrier walls, doors, floors, and ceilings are evaluated with the associated buildings and structures that are within the scope of subsequent license renewal.

System Intended Functions

Miscellaneous Structural Commodities perform the following safety-related functions: Miscellaneous Structural Commodities provide structural support, shelter and protection for safety-related SSCs. Therefore, Miscellaneous Structural Commodities are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Miscellaneous Structural Commodities provide structural support, shelter and protection for nonsafety-related SSCs whose failure could prevent performance of a safety-related function. Therefore, Miscellaneous Structural Commodities are within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2).

Miscellaneous Structural Commodities are relied upon for compliance with regulations for: Fire Protection (10 CFR 50.48), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, Miscellaneous Structural Commodities are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the Miscellaneous Structural Commodities can be found in the UFSAR, Sections 3.4, 3.8.1.1, 8.3.1.1.2.6, 9.3.2.2, and 9.5.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the miscellaneous structural commodities.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-39, Miscellaneous Structural Commodities.

The aging management review results for these component types are indicated in Table 3.5.2-39, Structures and Component Supports - Miscellaneous Structural Commodities - Aging Management Evaluation.

2.4.1.40 NSSS Supports

System Description

The Nuclear Steam Supply System (NSSS) supports are the plant structures and components that support the following reactor coolant system equipment and restrain it to the surrounding Containment:

Reactor Vessel Support

The reactor vessel is supported by six sliding foot assemblies mounted to the top of the neutron shield tank. The sliding foot assemblies are bolted to pads that are integral to and located beneath each of the reactor vessel primary loop nozzles. The sliding foot assemblies are designed to restrain lateral and rotational movement of the reactor vessel while allowing thermal expansion. Vertical loading is transmitted from the reactor vessel nozzle pads through the sliding foot assemblies, down through the tank structure and cylindrical skirt below, down to the Containment mat. The cylindrical skirt is secured to the Containment mat by anchor bolts. Overturning moments and horizontal forces are resisted by the concrete biological shield wall through a layer of grout, which fills the upper portion of the gap between the neutron shield tank and the surrounding concrete biological shield wall.

The neutron shield tank is a double-walled cylindrical structure that is filled with corrosion inhibited water that limits heat transfer to the concrete biological shield wall. The tank also serves to minimize gamma and neutron heating of the concrete biological shield wall, and to attenuate neutron radiation outside of the concrete biological shield wall to acceptable limits.

Reactor Coolant Pump Support

Each reactor coolant pump is mounted to a support frame. The frame is supported above the cubicle floor by pin-ended columns. This arrangement provides vertical support for the pump, while permitting free movement in the horizontal plane. The design of the support frame permits radial thermal expansion of the reactor coolant pump feet utilizing low friction bearing plates. Lateral seismic restraint for the pump is provided by hydraulic snubbers installed between the pump support frame and the lower support frame of the associated steam generator.

<u>Steam Generator Support</u>

Each steam generator is supported by a structural support assembly that consists of a lower support frame and an upper support ring. The lower support frame is a rigid structure that carries the weight of the steam generator. The lower support frame slides on lubricated bearing plates located under each corner column to permit thermal expansion of the reactor coolant piping from the reactor to the steam generator. The four columns also transmit vertical forces from the steam generator to the cubicle floor. The upper support consists of a pair of snubbers and a pair of rigid restraints attached to the upper support ring. The attachment of the lower support frame to the four pads on the steam generator bottom head permits radial thermal expansion of the steam generator.

<u>Pressurizer Support</u>

The pressurizer vessel is mounted in a rigid ring girder that is suspended by hanger columns from above. The support ring girder is restrained to the internal Containment wall by two bracket assemblies that prevent movement in lateral directions, while permitting vertical thermal growth. In addition, antisway brackets welded to the shell of the pressurizer fit into striker plate assemblies embedded in the concrete floor close to the center of gravity of the pressurizer vessel. These brackets permit the pressurizer vessel to expand vertically but restrain horizontal displacements.

<u>Other Class 1 Supports</u>

In addition to the aforementioned reactor coolant system equipment supports, NSSS Supports include supports for ASME Class 1 piping and components.

System Evaluation Boundary

The evaluation boundary for the NSSS Supports includes the supports for NSSS equipment and other ASME Class 1 piping and components. The evaluation boundary for NSSS Supports lies between the integral attachment on piping and equipment being supported and it includes bolting; grout; sliding surfaces; spring hangers; guides; stops; stainless steel elements associated with support members and dust covers; and steel elements associated with support members, bearing plates, baseplates, and connections, including maraging steel. Exposed portions of the embedded components (i.e., end portion of threaded anchor and nut) and grout are evaluated with the NSSS supports.

Concrete supporting structures (including the embedded portion of threaded anchor) are evaluated with the Containment. Integral attachments for the NSSS piping and equipment are evaluated for aging management with the specific NSSS equipment. The neutron shield tank is evaluated with the reactor coolant system. Supports for ASME Class 2 and Class 3 piping and components are evaluated with Component Supports.

Snubbers are active components and not subject to aging management.

System Intended Functions

NSSS Supports provide structural support and protection for safety-related SSCs. Therefore, NSSS Supports are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

UFSAR References

Additional details of the NSSS Supports can be found in the UFSAR, Sections 3.8.2.2.1 and 5.5.9.2; and Figures 5.5-8, 5.5-9, and 5.5-10.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the NSSS supports.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.4.1-40, NSSS Supports.

The aging management review results for these component types are indicated in Table 3.5.2-40, Structures and Component Supports - NSSS Supports - Aging Management Evaluation.

Intentionally Blank

Screening Results Tables: Containment, Structures and Component Supports

Table 2.4.1-1 Containment

Structural Member	Intended Function(s)
Blind flange (electrical penetrations)	Pressure Boundary
Bolting	Pressure Boundary, Structural Support
Concrete blocks	Enclosure Protection
Concrete elements	Enclosure Protection, Fire Barrier, Flood Barrier, Jet Impingement Shield, Missile Barrier, Pressure Boundary, Structural Support
Containment liner	Pressure Boundary, Structural Support
Containment sump liner	Pressure Boundary, Structural Support
Equipment hatch, personnel air lock, emergency escape locks, and accessories (hinges, pins, closure mechanisms)	Enclosure Protection, Missile Barrier, Pressure Boundary, Structural Support
Fuel transfer tube enclosure protection shield	Enclosure Protection, Structural Support
Penetrations (electrical)	Pressure Boundary, Structural Support
Penetrations (mechanical)	Enclosure Protection, Pressure Boundary, Structural Support
Porous concrete	Structural Support
Reactor cavity liner	Pressure Boundary, Structural Support
Seals and gaskets	Pressure Boundary, Structural Support
Service Level I coatings	Coating Integrity
Steel elements	Enclosure Protection, Missile Barrier, Structural Support
Waterproofing membrane	Enclosure Protection, Flood Barrier

See Table 2.1-1 for definitions of intended functions.

The aging management review results for these component types are indicated in Table 3.5.2-1, Containment Structure - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-2 Administration Building

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Structural Support
Doors	Enclosure Protection, Fire Barrier
Masonry block walls	Enclosure Protection, Fire Barrier, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-2, Structures and Component Supports - Administration Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-3 Auxiliary Building

Structural Member	Intended Function(s)
Aluminum elements	Enclosure Protection
Bolting	Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Structural Support
Doors	Enclosure Protection, Fire Barrier, Missile Barrier
Masonry block walls	Enclosure Protection, Fire Barrier, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-3, Structures and Component Supports - Auxiliary Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-4 Auxiliary Feedwater Pump House

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Missile Barrier, Structural Support
Steel elements	Enclosure Protection, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-4, Structures and Component Supports - Auxiliary Feedwater Pump House - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-5 Auxiliary Feedwater Tunnel

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Missile Barrier, Structural Support
Stainless steel elements	Enclosure Protection, Missile Barrier, Structural Support
Steel elements	Enclosure Protection, Missile Barrier, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-5, Structures and Component Supports - Auxiliary Feedwater Tunnel - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-6 Boron Recovery Building

Structural Member	Intended Function(s)
Aluminum elements	Enclosure Protection
Bolting	Structural Support
Concrete elements	Enclosure Protection, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-6, Structures and Component Supports - Boron Recovery Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-7 Casing Cooling Pump House

Structural Member	Intended Function(s)
Aluminum elements	Enclosure Protection
Bolting	Structural Support
Concrete elements	Enclosure Protection, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-7, Structures and Component Supports - Casing Cooling Pump House - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-8 Circulating Water Intake Tunnel Header

Structural Member	Intended Function(s)
Concrete elements	Structural Support
Steel piles	Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-8, Structures and Component Supports - Circulating Water Intake Tunnel Header - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-9 Containment Mat Subsurface Pump Access Shaft

Structural Member	Intended Function(s)
Concrete elements	Enclosure Protection, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-9, Structures and Component Supports - Containment Mat Subsurface Pump Access Shaft - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-10 Decontamination Building

Structural Member	Intended Function(s)
Aluminum elements	Enclosure Protection
Bolting	Structural Support
Concrete elements	Enclosure Protection, Structural Support
Masonry block walls	Enclosure Protection
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-10, Structures and Component Supports - Decontamination Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-11 Dikes, Firewalls, and Equipment Foundations

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Fire Barrier, Flood Barrier, Structural Support
Steel elements	Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-11, Structures and Component Supports - Dikes, Firewalls, and Equipment Foundations - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-12 Discharge Tunnel & Seal Pit

Structural Member	Intended Function(s)
Concrete elements	Water Barrier, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-12, Structures and Component Supports - Discharge Tunnel & Seal Pit - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-13 Domestic Water Treatment Building

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Structural Support
Masonry block walls	Enclosure Protection, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-13, Structures and Component Supports - Domestic Water Treatment Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-14 Duct Banks

Structural Member	Intended Function(s)
Concrete elements	Enclosure Protection, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-14, Structures and Component Supports - Duct Banks - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-15 Flood Protection Dike

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Structural Support
Earthen dike and embankment	Flood Barrier, Structural Support
Piping, piping components	Flood Barrier
Steel elements	Structural Support
Valve body	Flood Barrier

The aging management review results for these component types are indicated in Table 3.5.2-15, Structures and Component Supports - Flood Protection Dike - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-16 Fuel Building

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Flood Barrier, Missile Barrier, Structural Support
Masonry block walls	Enclosure Protection, Structural Support
Roofing membrane	Enclosure Protection
Spent fuel pool liner plates	Enclosure Protection, Pressure Boundary, Structural Support
Stainless steel elements	Enclosure Protection, Pressure Boundary, Structural Support
Steel elements	Enclosure Protection, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-16, Structures and Component Supports - Fuel Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-17 Fuel Oil Pump House

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Missile Barrier, Structural Support
Steel elements	Enclosure Protection, Missile Barrier, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-17, Structures and Component Supports - Fuel Oil Pump House - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-18 Intake Structure

Structural Member	Intended Function(s)
Aluminum elements	Enclosure Protection
Bolting	Structural Support
Concrete elements	Water Barrier, Enclosure Protection, Fire Barrier, Missile Barrier, Structural Support
Masonry block walls	Enclosure Protection, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Flood Barrier, Filtration, Missile Barrier, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-18, Structures and Component Supports - Intake Structure - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-19 Main Steam Valve House

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Structural Support
Masonry block walls	Enclosure Protection, Structural Support
Steel elements	Enclosure Protection, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-19, Structures and Component Supports - Main Steam Valve House - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-20 Maintenance Building

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Structural Support
Masonry block walls	Enclosure Protection, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-20, Structures and Component Supports - Maintenance Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-21 Manholes

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Missile Barrier, Structural Support
Steel elements	Enclosure Protection, Missile Barrier, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-21, Structures and Component Supports - Manholes - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-22 New Fuel Receiving Building

Structural Member	Intended Function(s)
Aluminum elements	Enclosure Protection
Bolting	Structural Support
Concrete elements	Enclosure Protection, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-22, Structures and Component Supports - New Fuel Receiving Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-23 Quench Spray Pump House

Structural Member	Intended Function(s)
Aluminum elements	Enclosure Protection
Bolting	Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-23, Structures and Component Supports - Quench Spray Pump House - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-24 Safeguards Building

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Missile Barrier, Structural Support
Steel elements	Enclosure Protection, Missile Barrier, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-24, Structures and Component Supports - Safeguards Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-25 SBO Building

Structural Member	Intended Function(s)
Aluminum elements	Enclosure Protection
Bolting	Structural Support
Concrete elements	Enclosure Protection, Flood Barrier, Structural Support
Masonry block walls	Enclosure Protection, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-25, Structures and Component Supports - SBO Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-26 SBO Structures for Offsite Power

Structural Member	Intended Function(s)
Bolting	Structural Support
Carbon fiber reinforced polymer wrap	Structural Support
Concrete elements	Enclosure Protection, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-26, Structures and Component Supports - SBO Structures for Offsite Power - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-27 Security Diesel Building

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Structural Support
Steel elements	Enclosure Protection, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-27, Structures and Component Supports - Security Diesel Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-28   Security Lighting Poles

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Structural Support
Steel elements	Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-28, Structures and Component Supports - Security Lighting Poles - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-29 Service Building

Structural Member	Intended Function(s)
Aluminum elements	Enclosure Protection
Bolting	Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Pressure Boundary, Structural Support
Doors	Enclosure Protection, Fire Barrier, Flood Barrier, Missile Barrier, Pressure Boundary
Masonry block walls	Enclosure Protection, Fire Barrier, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Flood Barrier, Missile Barrier, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-29, Structures and Component Supports - Service Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-30 Service Water Pump House

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Flood Barrier, Missile Barrier, Structural Support
Steel elements	Enclosure Protection, Filtration, Missile Barrier, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-30, Structures and Component Supports - Service Water Pump House - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-31 Service Water Reservoir

Structural Member	Intended Function(s)
Concrete elements	Enclosure Protection, Structural Support
Earthen dike and embankment	Water Barrier, Source of Cooling, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-31, Structures and Component Supports - Service Water Reservoir - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-32 Service Water Valve House

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Flood Barrier, Missile Barrier, Structural Support
Steel elements	Enclosure Protection, Missile Barrier, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-32, Structures and Component Supports - Service Water Valve House - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-33 Tank Foundations and Missile Barriers

Structural Member	Intended Function(s)
Bolting	Structural Support
Caulking and sealants	Enclosure Protection
Compressible seal	Enclosure Protection
Concrete elements	Missile Barrier, Structural Support
Grout	Structural Support
Stainless steel elements	Missile Barrier
Steel elements	Missile Barrier

The aging management review results for these component types are indicated in Table 3.5.2-33, Structures and Component Supports - Tank Foundations and Missile Barriers - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-34 Turbine Building

Structural Member	Intended Function(s)
Aluminum elements	Enclosure Protection
Bolting	Structural Support
Concrete elements	Enclosure Protection, Fire Barrier, Flood Barrier, Structural Support
Doors	Enclosure Protection, Fire Barrier
Masonry block walls	Enclosure Protection, Fire Barrier, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Flood Barrier, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-34, Structures and Component Supports - Turbine Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-35 Vaults, Enclosures, and Pits

Structural Member	Intended Function(s)
Bolting	Structural Support
Concrete elements	Enclosure Protection, Missile Barrier, Structural Support
Steel elements	Enclosure Protection, Missile Barrier, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-35, Structures and Component Supports - Vaults, Enclosures, and Pits - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-36 Waste Disposal Building

Structural Member	Intended Function(s)
Aluminum elements	Enclosure Protection
Bolting	Structural Support
Concrete elements	Enclosure Protection, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-36, Structures and Component Supports - Waste Disposal Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-37 Waste Solidification Building

Structural Member	Intended Function(s)
Aluminum elements	Enclosure Protection
Bolting	Structural Support
Concrete elements	Enclosure Protection, Structural Support
Roofing membrane	Enclosure Protection
Steel elements	Enclosure Protection, Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-37, Structures and Component Supports - Waste Solidification Building - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-38   Component Supports

Component Type	Intended Function(s)
Aluminum elements	Enclosure Protection, Structural Support
Bolting	Structural Support
Grout	Structural Support
Sliding surfaces	Structural Support
Spring hangers; guides; stops	Structural Support
Stainless steel elements	Structural Support
Steel elements	Enclosure Protection, Structural Support
Vibration isolation elements	Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-38, Structures and Component Supports - Component Supports - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-39 Miscellaneous Structural Commodities

Component Type	Intended Function(s)
Bolting	Structural Support
Electrical Enclosures	Enclosure Protection, Leakage Boundary (Spatial), Structural Support
Fireproofing and fire barriers	Enclosure Protection, Fire Barrier, Flood Barrier
Penetration seals	Enclosure Protection, Fire Barrier, Flood Barrier, Pressure Boundary
Penetration sleeves	Structural Support
Seismic gap covers	Enclosure Protection, Fire Barrier
Seismic gap filler material	Enclosure Protection

The aging management review results for these component types are indicated in Table 3.5.2-39, Structures and Component Supports - Miscellaneous Structural Commodities - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.4.1-40 NSSS Supports

Component Type	Intended Function(s)
Bolting	Structural Support
Grout	Structural Support
Sliding surfaces	Structural Support
Spring hangers; guides; stops	Structural Support
Stainless steel elements	Structural Support
Steel elements	Structural Support

The aging management review results for these component types are indicated in Table 3.5.2-40, Structures and Component Supports - NSSS Supports - Aging Management Evaluation.

2.5 SCOPING AND SCREENING RESULTS: ELECTRICAL AND INSTRUMENTATION AND CONTROL SYSTEMS

Scoping to determine the electrical and I&C systems that fall within subsequent license renewal was performed according to the methodology in Section 2.1.4 with results presented in Table 2.2-1. Results of electrical system scoping presented in Section 2.2 include not only plant electrical systems, but also switchyard components credited with restoring offsite power following a Station Blackout (SBO) event. The boundary for the SBO recovery path from both onsite and offsite power is depicted in a simplified diagram in Figure 2.1-1.This figure also includes the Alternate AC power source used during the SBO coping period. Screening of in-scope electrical and I&C systems, as well as electrical and I&C components within in-scope mechanical systems, was performed in accordance with the methodology discussed in Section 2.1.5.

Identification of Electrical Components and Commodities

The first step in the screening process for electrical components and commodities is to identify electrical components and commodities within the electrical, I&C and mechanical systems based on plant design documents.

Application of Screening Criterion 10 CFR 54.21(a)(1)(i) to Electrical Components and Commodities

Following identification of electrical components and commodities, the criteria of 10 CFR 54.21(a)(1)(i) were applied to identify components and commodities that perform their functions without moving parts or without a change in configuration or properties. The following electrical components and commodity groups were determined to meet the screening criteria of 10 CFR 54.21(a)(1)(i):

- Cables and Connections
  - Cable connections (metallic parts)
  - Connector contacts for electrical connections exposed to borated water leakage
  - Electrical insulation material for electrical cables and connections
  - Fuse Holder - not part of active equipment (insulation material)
  - Fuse Holder - not part of active equipment (metallic clamps)
  - Switchyard bus and connections
  - Transmission conductors
  - Transmission connections
  - Cable tie-wraps
  - Uninsulated ground conductors
- Metal Enclosed Bus
- High Voltage Insulators
- Containment Electrical and I&C Penetrations

<u>Elimination of Electrical Components with No License Renewal Intended Functions</u>

The following electrical components (cable tie-wraps and uninsulated ground conductors) were determined to not have a license renewal intended function and were eliminated from the electrical commodity groups:

<u>Cable Tie-Wraps</u>

Cable tie-wraps are used in cable installations as cable ties. Cable tie-wraps hold groups of cable together for restraint and ease of maintenance. Cable tie-wraps are used to bundle wires and cables together to keep the wire and cable runs neat and orderly. Cable tie-wraps are used to restrain wires and cables within raceways to facilitate cable installation. There are no current license basis requirements that cable tie-wraps remain functional during and following design basis events. Cable tie-wraps are not credited for maintaining cable ampacity, ensuring maintenance of cable minimum bending radius, or maintaining cables within vertical raceways. The seismic qualification of cable trays does not credit the use of cable tie-wraps. Cable tie-wraps are not credited in the design basis in terms of any 10 CFR 54.4 intended function. Therefore, cable tie-wraps are not within the scope of subsequent license renewal and are not subject to an aging management review.

Uninsulated Ground Conductors

The uninsulated ground conductor component group is comprised of grounding cable and associated connectors. Ground conductors are provided for equipment and personnel protection. They do not perform an intended function for license renewal. Therefore, uninsulated ground conductors are not within the scope of subsequent license renewal and are not subject to aging management review.

Application of Screening Criterion 10 CFR 54.21(a)(1)(ii) to Electrical Commodities and Components

Subsequently, the screening criterion of 10 CFR 54.221(a)(1)(ii) was applied to the list of components and commodity groups that remained following application of the 10 CFR 21(a)(1)(i) criterion. 10 CFR 54.21(a)(1)(ii) allows the exclusion of those commodities that are subject to replacement based on a qualified life or specified time period. The only electrical commodities identified for exclusion by 10 CFR 54.21(a)(1)(ii) are electrical and I&C components and commodities included in the Environmental Qualifications of Electric Equipment aging management program. This is because electrical and I&C components and commodities included in the EQ Program have defined qualified lives and are replaced prior to the expiration of their qualified lives. No electrical and I&C components and commodities within the EQ Program are subject to aging management review in accordance with 10 CFR 54.21(a)(1)(ii). See Section 4.4 for the TLAA evaluation of the Environmental Qualification of Electric Equipment aging management program.

A portion of the electrical penetrations are environmentally qualified. These electrical penetrations are evaluated as a time-limited aging analysis and are managed by the *Environmental Qualification of Electric Equipment* program (B3.3). For the remainder of the electrical penetrations, the electrical continuity of electrical penetration pigtails and associated connections that could potentially be exposed to an adverse localized environment is included in the evaluation for the electrical insulation material for electrical cables and connections component group under the Cables and Connections commodity group in Section 2.5.1.1 The pressure boundary, and structural support intended functions of electrical penetrations are included in the evaluation for Containment in Section 2.4.1.1.

Electrical Components and Commodity Groups Subject to Aging Management Review

The remaining electrical components and commodity groups, all or part of which are not in the EQ Program, require aging management review and are discussed in Sections 2.5.1.1, 2.5.1.2, and 2.5.1.3 below.

Components that provide support functions for electrical and I&C components, for example, electrical panels and enclosures, instrument racks, cable tray, and conduit, are assessed with the structural support commodity group in Section 2.4.

2.5.1 ELECTRICAL COMPONENT GROUPS

2.5.1.1 Cables And Connections

Component Group Description

The electrical commodity group identified as "Cables and Connections" includes the following electrical and I&C component groups:

-Cable connections (metallic parts)

-Connector contacts for electrical connections exposed to borated water leakage

-Electrical insulation material for electrical cables and connections

-Fuse Holder - not part of active equipment (insulation material)

-Fuse Holder - not part of active equipment (metallic clamps)

-Switchyard bus and connections

-Transmission conductors

-Transmission connections

Numerous insulated cables and connections are included in the EQ program and, therefore, are not subject to an aging management review in accordance with the screening criteria of 10 CFR 54.21(a)(1)(ii). Insulated cables and connections not included in the EQ program meet the criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an aging management review.

The electrical and I&C components included within the component groups consist of electrical conductors and termination devices that deliver voltage, current, and/or signals from sources to end use devices, and are passive in nature. These electrical components are further described below.

<u>Cable Connections (Metallic Parts)</u>

The cable connections (metallic parts) component group includes metallic portions of electrical terminations that are not included in the EQ program. Termination devices within this component group include compression type terminal lugs, bolted connections, splices, and terminal blocks.

<u>Connector Contacts for Electrical Connections Exposed to Borated Water Leakage</u>

The connector contacts for electrical connections exposed to borated water leakage component group includes connector contacts, not included in the EQ program, that are exposed to borated water leakage.

<u>Electrical Insulation Material for Electrical Cables and Connections</u>

The electrical insulation material for electrical cables and connections component group includes insulation material for the following component groups that are not included in the EQ program:

-Insulation material for electrical cables and connections

-Insulation material for electrical cables and connections used in instrumentation circuits

-Insulation material for electrical penetration pigtails

-Insulation material for inaccessible or below ground medium-voltage cable

-Insulation material for inaccessible or below ground I&C cable

-Insulation material for inaccessible or below ground low-voltage power cable

Underground insulated medium-voltage cable that is part of the SBO offsite power recovery path and connects the switchyard breakers to the reserve station service transformers (RSSTs) is included within the scope of subsequent license renewal.

Fuse Holder - Not Part of Active Equipment (Insulation Material)

The fuse holder - not part of active equipment (insulation material) component group includes fuse holders that are not part of active equipment and are not included in the EQ program. The insulation material for these fuse holders includes the mounting block for metallic components.

Fuse Holder - Not Part of Active Equipment (Metallic Clamps)

The fuse holder - not part of active equipment (metallic clamps) component group includes fuse holders that are not part of active equipment and are not included in the EQ program. The metallic portions of these fuse holders include spring-loaded clips and bolted lugs to connect the fuse ends.

Switchyard Bus and Connections

The switchyard bus and connections component group includes the passive, long-lived switchyard components and connections that are part of the power feeds credited for recovery of offsite power following an SBO event. The boundary for these power feeds is the first circuit breakers downstream of switchyard buses 3, 4, and 5, and their associated disconnect switches. These components include the 3.5" aluminum switchyard bus, bare aluminum cable, and termination devices that connect active components (disconnect switches and 34.5 kV circuit breakers) from switchyard buses 3, 4, and 5 to the RSSTs.

Also included in the switchyard bus and connections component group is the 4" x 4" aluminum angle bus (switchyard bus) on the low voltage side of the RSSTs, the 5” and 6" aluminum tube bus (switchyard bus) from the low voltage side of the RSSTs to cable connections at the turbine building, and 1590 MCM bare aluminum cable that connects the RSST high voltage bushings to the underground cables from the 34.5 kV switchyard buses and the RSST low voltage bushings to the 4" x 4" aluminum angle bus (switchyard bus) and then to the 5” and 6" aluminum tube bus (switchyard bus). Although these components are within the station, their material type, environment, and aging effects are similar to corresponding switchyard components. Therefore, they are included in the switchyard bus and connections component group for evaluation.

Transmission Conductors

The transmission conductors component group includes the 34.5 kV overhead conductors that are part of the 34.5 kV overhead lines, available as back-up in case of a failed underground line or alternate feeder when an underground line is out of service, from buses 3, 4, and 5 to the RSSTs. These conductors are 545.6 MCM Aluminum Conductor Aluminum Reinforced cables.

Transmission Connections

The transmission connections component group includes the connections for the 34.5 kV transmission conductors that are available as back-up in case of a failed underground line or alternate feeder when an underground line is out of service from buses 3, 4, and 5 to the RSSTs.

Component Group Boundary

The cable and connections commodity group includes those electrical and I&C components listed in the cable and connections component groups that are used in systems determined to be in-scope for subsequent license renewal. In addition to the station electrical systems, switchyard components credited in the restoration of offsite power following an SBO event were included within the scope of subsequent license renewal. The switchyard components credited for recovery from an SBO event begin at the first 34.5 kV circuit breakers and associated disconnect switches downstream of 34.5 kV Buses 3, 4, and 5 and continue through the reserve station service transformers A, B, and C to transfer buses D, E, and F.

Stored Equipment

The cables and connections commodity group includes cable and terminal lugs stored in the warehouse at NAPS for the purpose of energizing RHR pumps from an alternate source. This stored equipment is within the scope of subsequent license renewal.

Support Components and Structures

Components that support electrical and I&C components, for example cable tray, conduit, structural supports, steel poles, racks and panels, are assessed as part of the structural evaluation.

Component Group Intended Functions

Components in the cables and connections commodity group perform the intended functions of “conducts electricity” and “insulates” for circuits that supply electrical power, control and indication signals to safety-related components. Therefore, cables and connections are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1). Components in the cables and connections commodity group perform the intended functions of “conducts electricity” and “insulates” for circuits that supply electrical power, control and indication signals to nonsafety-related components that support safety-related functions. Therefore, cables and connections are within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2). Components in the cables and connections commodity group perform the intended functions of "conducts electricity" and "insulates" for circuits that are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, cables and connections are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the cables and connections can be found in the UFSAR, Section 8.1.1.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the cables and connections.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.5.1-1, Cables And Connections.

The aging management review results for these component types are indicated in Table 3.6.2-1, Electrical and Instrumentation and Controls - Cables And Connections - Aging Management Evaluation.

2.5.1.2 High Voltage Insulators

Component Group Description

The electrical commodity group identified as "High-Voltage Insulators" includes those station post and suspension insulators that support overhead conductors (transmission conductors and switchyard bus) that are part of the SBO offsite power recovery path. High-voltage insulators are passive in nature. The insulating portion of high-voltage insulators is made of porcelain, toughened glass, or polymer. The high-voltage insulator commodity group was evaluated against 10 CFR 54.21(a)(1)(ii) and determined to not be included in the EQ program. Therefore, high-voltage insulators are subject to aging management review.

<u>Toughened Glass</u>

Porcelain and toughened glass are similar in design and construction with the chief difference being the materials used to manufacture the porcelain and glass insulating shells. Both materials are ceramics that experience the same external aging effects of reduced insulation resistance from excessive surface contamination. Both materials rely on surface rinsing from precipitation or mechanical washing to clean contaminants from the shed surfaces. Both materials have been in service in the utility industry for over 60 years worldwide and are considered to be mature technologies, generally standardized, and readily interchangeable with high reliability and low cost. However, unlike porcelain, toughened glass does not experience micro cracks, micro structures and crystallographic structure or defects. Because of this, the electrical resistance and capacitance of the toughened glass insulator are defined by the chemistry of the glass and the shape and dimensions of the shell and are not affected by aging or time. Also, toughened glass insulators do not experience loss of material as an aging effect. Loss of material is a result of event driven external damage from an outside agency.

Tests of toughened glass insulators removed from field service after 20 to 40 years of operation in various climates including desert, coastal, and tropical conditions were performed to determine the degree of aging experienced. Mechanical strength tests, thermo mechanical tests, and electrical wave front and dielectric strength tests were performed on toughened glass insulators used in AC and DC transmission applications. Testing included heavily contaminated insulators. Test results indicated no signs of aging affecting either electrical or mechanical performance.

Inspection procedures for toughened glass insulators are the same as for porcelain insulators. Both types are cap and pin (suspension) insulators with similar metal and cement materials, and method of construction, and the same aging effect of loss of material from corrosion and mechanical wear. Inspection for mechanical wear (visual) is the same for both types of insulators. The insulating material for the two types of insulators has the same aging effect of reduced insulation resistance from excessive surface contamination. Inspection for excessive surface contamination (visual) is the same for both types of insulators.

<u>Polymer</u>

Post insulators used in the switchyard at NAPS include the following main elements: metallic end fittings of similar material as porcelain insulators (aluminum, galvanized steel, iron), fiberglass rod forming the structure of the insulator, and a polymeric weather shed system consisting of a sheath and weather sheds (composed of either silicone rubber or ethylene propylene rubber).

The fiberglass rod that forms the core of the insulator is designed to carry the mechanical load of the insulator. The fiberglass rod tends to be a good electrical insulator provided it remains dry and uncontaminated. A polymer sheath is used to hermetically seal the fiberglass rod against environmental effects and to provide sufficient leakage distance to withstand both environmental and electrical stresses. Weather sheds, generally manufactured of the same polymeric material as the sheath, are used to increase the electrical resistance of the insulator.

The Electric Power Research Institute (EPRI) identified four failure mechanisms of the fiberglass rod that account for 95% of polymer insulator failures. These are: destruction of the rod by discharge activity, flashunder, brittle fracture, and mechanical failure of the rod. The first two failure types, discharge activity and flashunder, represent a slow degradation activity that occurs when the core rod is exposed to the environment because of functional failure of the polymer weather shed system or the end fitting seal. Brittle fracture, also known as stress corrosion cracking, is a mechanical failure of the fiberglass rod. Brittle fracture occurs due to the presence of acids in the proximity to the fiberglass rod. Acids can originate either from external or internal sources.

Externally, acids may be generated by discharge activity, or may come from acid rain or other chemical reactions. Internally, acid may form inside the insulator when moisture comes into contact with the fiberglass rod and reacts with chemical residue in or on the surface of the rod (such as hardener left over from the manufacturing process). The presence of acids, in combination with tensile stress of the rod, creates the environment for stress corrosion cracking of the rod. Mechanical failure modes include component separation under load and fiberglass rod failure. Mechanical failures can result from mishandling, errors in the manufacturing process, and degradation.

An important characteristic of polymer insulator technology, and a difference between polymer and ceramic insulators, is how the surface material wets. The surface wetting properties of a polymer insulator can be categorized as either hydrophobic or hydrophilic. Silicone rubber tends to be hydrophobic in that its surface resists wetting by forming water into beads. This prevents a continuous water layer from forming on the surface of the insulator which, in turn, reduces leakage currents and the associated discharge activity. Ethylene propylene rubber is hydrophilic in nature and allows a thin film of water to form on its surface. Polymer insulators have been shown to exhibit better short term resistance to contamination flashover than ceramic insulators. This has been attributed to the significant difference in the geometry and surface wettability of polymeric and ceramic insulators. However, unlike ceramic insulators, surface aging can be accelerated by contamination. Also, polymer weather sheds can experience swelling and embrittlement in certain chemical environments.

Visual inspection is an accepted inspection technique for determining if loss of material or reduced electrical insulation resistance is occurring due to aging. Visual inspection can identify operational effects such as tracking and flashover, and polymer defects such as cracking, crazing, chalking, embrittlement, and buildup of contaminants. Also, cracking or other defects of the sheath that protects the fiberglass rod is an indicator that damage may be occurring to the rod that will lead to mechanical failure. As with ceramic insulators, visual inspection is effective in determining if there is loss of material occurring with metallic components used to attach polymer insulators to conductors and supports.

Component Group Boundary

The high-voltage insulators commodity group includes SBO offsite power recovery path insulators that support 34.5 kV transmission conductors in the overhead lines that are available as back-up for the underground cables from switchyard buses 3, 4, and 5 to the reserve station service transformers, 34.5 kV conductors that connect the disconnect switches associated with buses 3, 4, and 5 circuit breakers to underground cables that feed the reserve station service transformers, 34.5 kV and 4,160V overhead bare conductors that connect the reserve station service transformers to both the underground cables from the switchyard and the overhead switchyard bus to the turbine building, and 4,160V overhead switchyard bus from the reserve station service transformers to cables located at the turbine buildings. The boundary for the SBO offsite power recovery path is the first circuit breakers downstream of switchyard buses 3, 4, and 5, and their associated disconnect switches.

Components that support high-voltage insulators, for example structural supports and steel poles, are assessed as part of the structural evaluation.

Component Group Intended Functions

Components in the high-voltage insulators commodity group perform the intended function of “insulates” for circuits that are relied upon for compliance with regulations for Station Blackout (10 CFR 50.63). Therefore, High-Voltage Insulators are within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

UFSAR References

Additional details of the high voltage insulators can be found in the UFSAR, Section 8.1.1.

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the high voltage insulators.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.5.1-2, High Voltage Insulators.

The aging management review results for these component types are indicated in Table 3.6.2-2, Electrical and Instrumentation and Controls - High Voltage Insulators - Aging Management Evaluation.

2.5.1.3 Metal Enclosed Bus

System Description

The electrical commodity group identified as “Metal Enclosed Bus” includes the following component groups:

-Metal enclosed bus - bus and connection insulation

-Metal enclosed bus - bus and connections

-Metal enclosed bus - bus enclosure

The electrical components included within the component groups consist of electrical conductors and termination devices that deliver voltage, current, and/or signals from sources to end use devices, materials that insulate electrical conductors and terminations, and metal enclosures that shelter and protect. The only type of metal enclosed bus in-scope of subsequent license renewal is non-segregated phase bus. Metal enclosed bus is not included in the EQ program. Therefore, metal enclosed bus meets the screening criteria for 10 CFR 54.21(a)(1)(ii) and is subject to aging management review.

Component Group Boundary

The Metal Enclosed Bus commodity group includes the following sections of non-segregated phase buswork:

-MEB connecting Transfer Bus D cubicle 15D2 to Unit 2 Bus A switchgear cubicle 25A1

-MEB connecting Transfer Bus E cubicle 15E2 to Unit 2 Bus B switchgear cubicle 25B1

-MEB connecting Transfer Bus F cubicle 15F2 to Unit 1 Bus C switchgear cubicle 15C1

-MEB connecting emergency switchgear Bus 1H cubicle 15H10 to cubicle 15H11

-MEB connecting emergency switchgear Bus 1J cubicle 15J8 to cubicle 15J10

-MEB connecting emergency switchgear Bus 2H cubicle 25H8 to cubicle 25H9

-MEB connecting emergency switchgear Bus 2J cubicle 25J8 to cubicle 25J9

-MEB connecting from the bushing box (including the termination bushings) at the A RSST manual switch to Bus 1G cubicle 15G11, and Bus 2G cubicle 25G8

Structural supports that support metal enclosed bus are assessed as part of the structural evaluation.

Component Group Intended Functions

Sections of Metal Enclosed Bus that perform the intended functions of “conducts electricity” and “insulates” supply electrical power to safety-related switchgear. Therefore, Metal Enclosed Bus is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1). Sections of Metal Enclosed Bus that perform the intended functions of “conducts electricity” and “insulates” supply power to nonsafety-related switchgear that supplies power to safety-related switchgear. Therefore, Metal Enclosed Bus is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2). Sections of Metal Enclosed Bus that perform the intended functions of “conducts electricity” and “insulates” are relied on for compliance with regulations for Fire Protection (10 CFR 50.48) and Station Blackout (10 CFR 50.63). Therefore, Metal Enclosed Bus is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

The Metal Enclosed Bus enclosure performs the intended function of “enclosure protection.”

UFSAR References

None

Subsequent License Renewal Boundary Drawings

There are no subsequent license renewal boundary drawings for the metal enclosed bus.

Components Subject to Aging Management Review

The component types subject to aging management review are indicated in Table 2.5.1-3, Metal Enclosed Bus.

The aging management review results for these component types are indicated in Table 3.6.2-3, Electrical and Instrumentation and Controls - Metal Enclosed Bus - Aging Management Evaluation.

Screening Results Tables: Electrical and Instrumentation and Controls Commodity Groups

Table 2.5.1-1 Cables And Connections

Component Type	Intended Function(s)
Cable Connections (metallic parts)	Conducts Electricity
Connector Contacts for Electrical Connections Exposed to Borated Water Leakage	Conducts Electricity
Fuse Holder - Not Part of Active Equipment (Insulation Material)	Insulate
Fuse Holder - Not Part of Active Equipment (Metallic Clamps)	Conducts Electricity
Insulation Material for Electrical Cable and Connections Used in Instrumentation Circuits	Insulate
Insulation Material for Electrical Cables and Connections	Insulate
Insulation Material for Inaccessible or Below Ground Instrumentation and Control Cable	Insulate
Insulation Material for Inaccessible or Below Ground Low Voltage Power Cable	Insulate
Insulation Material for Inaccessible or Below Ground Medium Voltage Cable	Insulate
Switchyard Bus and Connections	Conducts Electricity
Transmission Conductors	Conducts Electricity
Transmission Connectors	Conducts Electricity

The aging management review results for these component types are indicated in Table 3.6.2-1, Electrical and Instrumentation and Controls - Cables And Connections - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.5.1-2 High Voltage Insulators

Component Type	Intended Function(s)
High Voltage Insulators	Insulate

The aging management review results for these component types are indicated in Table 3.6.2-2, Electrical and Instrumentation and Controls - High Voltage Insulators - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

Table 2.5.1-3 Metal Enclosed Bus

Component Type	Intended Function(s)
Bus and Connection Insulation	Insulate
Bus and Connections	Conducts Electricity
Bus Enclosure	Enclosure Protection

The aging management review results for these component types are indicated in Table 3.6.2-3, Electrical and Instrumentation and Controls - Metal Enclosed Bus - Aging Management Evaluation.

See Table 2.1-1 for definitions of intended functions.

3.0 AGING MANAGEMENT REVIEW RESULTS

This chapter provides the results of the aging management review for those structures and components identified in Table 2.2-1 as being subject to aging management review.

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,” dated July 2017. (Reference 1.7-3).

The major sections of this chapter are:

- Aging Management of Reactor Vessel, Internals, and Reactor Coolant System (Section 3.1)
- Aging Management of Engineered Safety Features (Section 3.2)
- Aging Management of Auxiliary Systems (Section 3.3)
- Aging Management of Steam and Power Conversion System (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 aging management review to determine aging effects requiring management are included in Table 3.0-1, Mechanical System Service Environments. The environments used in the aging management reviews are listed in the Environment column. The third column identifies one or more of the NUREG-2191 environments that were used when comparing the NAPS Aging Management Review results to the NUREG-2191 results. The Electrical and Structural aging management reviews use environment names consistent with the assigned NUREG-2191 items. The definitions of those environments correspond to the definitions in NUREG-2191 section IX.D

Most of the Aging Management Review (AMR) results information in Section 3 is presented in the following two tables:

Table 3.x.1 - where '3' indicates the SLRA section number, 'x' indicates the subsection number from NUREG-2191, and '1' indicates that this is the first table type in Section 3. For example, in the Reactor Vessel, Internals, and Reactor Coolant System subsection, this table would be number 3.1.1, in the Engineered Safety Features subsection, this table would be 3.2.1, and so on. For ease of discussion, this table will, hereafter, be referred to in this Section as “Table 1."

Table 3.x.2-y - where '3' indicates the SLRA section number, 'x' indicates the subsection number from NUREG-2191, and '2' indicates that this is the second table type in Section 3; and 'y' indicates the table number for a specific system. For example, for the reactor vessel, within the Reactor Vessel, Internals, and Reactor Coolant System subsection, this table would be 3.1.2-1 and for the reactor vessel internals, it would be Table 3.1.2-2. For the quench spray system, within the

Engineered Safety Features (ESF) subsection, this table would be 3.2.2-1. For the next system within the ESF subsection, it would be Table 3.2.2-2. For ease of discussion, this table will, hereafter, be referred to in this section as “Table 2."

Table Description

Table 1

The purpose of Table 1 is to provide a summary comparison of how the facility aligns with the corresponding tables of NUREG-2192. The table is essentially the same as Tables 3.1-1 through 3.6-1 provided in NUREG-2192, except that the “New, Modified, Deleted, Edited Item,” “ID” and “Type” columns have been replaced by an “Item Number” column, and the “GALL-SLR Item” column has been replaced by a “Discussion” column.

The “Item Number” column provides the reviewer with a means to cross-reference from Table 2 to Table 1.

The “Discussion” column is used to provide clarifying or amplifying information. The following are examples of information that might be contained within this column:

- “Further Evaluation Recommended” information or reference to where that information is located
- The name of a plant specific aging management program being used, if applicable
- Exceptions to the NUREG-2191 assumptions, if applicable
- A discussion of how the line is consistent with the corresponding line item in NUREG-2191, when that may not be intuitively obvious
- A discussion of how the item is different than the corresponding line item in NUREG-2191 when it may appear to be consistent (e.g., when there is exception taken to an aging management program that is listed in NUREG-2191), if applicable

The format of Table 1 provides the reviewer with a means of aligning a specific Table 1 item with the corresponding NUREG-2192 table item, thereby allowing for the ease of checking consistency.

Table 2

Table 2 provides the detailed results of the aging management reviews for those components identified in SLRA Section 2 as being subject to aging management review. There is a Table 2 for each of the systems within a Chapter 3 Section grouping. For example, the Engineered Safety Features System Group contains tables specific to the quench spray system, recirculation spray system, residual heat removal system and safety injection system. Table 2 consists of the following nine columns:

- Component Type
- Intended Function
- Material
- Environment
- Aging Effect Requiring Management
- Aging Management Programs
- NUREG-2191 Item
- Table 1 Item
- Notes

Component Type - The first column identifies all of the component types from Section 2 of the SLRA that are subject to aging management review. 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 2.1-1.

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 Electrical and Structural aging management reviews use environment names consistent with the assigned NUREG-2191 items. The definitions of those environments correspond to the definitions in NUREG-2191, Section IX.D.

Aging Effect Requiring Management - As part of the aging management review process, the aging effects that are required to be managed in order to maintain the intended function of the component type are identified for the material and environment combination. These aging effects requiring management are listed in the fifth column.

Aging Management Programs - The aging management programs used to manage the aging effects requiring management are listed in the sixth column of Table 2. Aging management programs are described in Appendix B.

NUREG-2191 Item - Each combination of component type, material, environment, aging effect requiring management, and aging management program that is listed in Table 2, is compared to NUREG-2191, with consideration given to the standard notes, to identify consistency. Consistency is documented by noting the appropriate NUREG-2191 item number in the seventh column of Table 2. If there is no corresponding item number in NUREG-2191, this field in column seven is marked “None.” Thus, a reviewer can readily identify the correlation between the plant-specific tables and the NUREG-2191 tables.

Table 1 Item - Each combination of component, material, environment, aging effect requiring management, and aging management program that has an identified NUREG-2191 item number must also have a Table 3.x.1 line item reference number. The corresponding line item from Table 1 is listed in the eighth column of Table 2. If there is no corresponding item in NUREG-2191, this field in column eight is marked “None.” The Table 1 Item allows correlation of the information from the two tables.

Notes - The notes provided in each Table 2 describe how the information in the table aligns with the information in NUREG-2191. Each Table 2 contains standard lettered notes and, if applicable, plant-specific numbered notes.

The standard lettered notes (e.g., A, B, C) provide standard information regarding comparison of the aging management review results with the NUREG-2191 Aging Management Table line item identified in the seventh column. In addition to the standard lettered notes, numbered plant-specific notes provide additional clarifying information when appropriate.

Table Usage

Table 1

The reviewer evaluates each item in Table 1 by moving from left to right across the table. Since the Component, Aging Effect, Aging Management Programs and Further Evaluation Recommended information is taken directly from NUREG-2192, no further analysis of those columns is required. The information intended to help the reviewer in this table is contained within the Discussion column. Here the reviewer will be given plant-specific information necessary to determine, in summary, how the NAPS 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 item are consistent with the material, environment, aging effect, and program(s) associated with the assigned NUREG-2191 item, followed by any clarifications or exceptions that may apply.

Table 2

Table 2 contains all of the Aging Management Review information for the plant, whether or not it aligns with NUREG-2191. For a given item within the table, the reviewer can see the intended function, material, environment, aging effect requiring management and aging management program combination for a particular component type within a system. Within each system or structure, the intended functions for each component type are consolidated for table listing. In addition, if there is a correlation between the combination in Table 2 and a combination in NUREG-2191, this will be identified by a referenced item number in column seven, NUREG-2191 Item. The reviewer can refer to the item number in NUREG-2191, if desired, to verify the correlation. If the column contains “None,” no corresponding combination in NUREG-2191 was found. As the reviewer continues across the table from left to right, within a given item, 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 item in Table 1 and see how the aging management program for this particular combination aligns with NUREG-2191.

Table 2 provides the reviewer with a means to navigate from the components subject to Aging Management Review (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.

Cumulative Fatigue Damage and TLAAs in Table 2

A fatigue analysis is considered to be a time-limited aging analysis (TLAA) as defined in 10 CFR 54.3 when it is within the current licensing basis and is based upon transient cycle assumptions associated with the current operating term. This includes explicit ASME Code, Section III, Class 1 analysis for components and ANSI B31.7 Class 1 analysis for piping as well as implicit ASME Code, Section III, Class 2 and 3 analysis for piping based on ANSI B31.1. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). Table 1 and Table 2 include an entry in the Aging Management Program column indicating “TLAA” for each line item that has a component for which a fatigue TLAA (explicit or implicit) has been identified. See SLRA Section 4.3 for details regarding the fatigue design bases, fatigue TLAAs identified, and TLAA evaluations for the subsequent period of extended operation.

Table 3.0-1 Mechanical System Service Environments

NAPS AMR Environment	Definition	NUREG-2191 Environment(s) Used for AMR Comparison [(1)]
Air - dry	Air that has been treated to reduce its dew point well below the system operating temperature. Within piping systems, unless otherwise specified, this environment may be either internal or external.	Air, Air - dry
Air – indoor, uncontrolled	Indoor air with temperatures higher than the dew point. Condensation can occur but only rarely, equipment surfaces are normally dry. For high temperature systems, this environment includes the potential for elevated temperatures that supports cumulative fatigue damage. This name is also used to describe the internal environment of undried compressed air.	Air, Air – indoor, uncontrolled, System temperature up to 288°C (550°F) System temperature up to 340°C (644°F)
Air - outdoor	The outdoor environment consists of moist, atmospheric air at temperatures and humidity, and exposure to weather, including precipitation and wind. The component is exposed to air and local weather conditions. Outdoor air does not include the potential to pool water; outdoor environments with the potential for pooled water are called raw water, condensation, or soil (for tank bottoms).	Air, Air – outdoor
Air with borated water leakage	Indoor air in areas that contain borated water systems have the potential for borated water leakage, with management by the Boric Acid Corrosion program.	Air with borated water leakage
Closed-cycle cooling water	Treated water subject to the Closed Treated Water Systems chemistry program. Closed-cycle cooling water describes the environment in treated closed cooling and heating systems.	Closed-cycle cooling water
Closed-cycle cooling water >60°C (>140°F)	Treated water subject to the Closed Treated Water Systems chemistry program. Closed-cycle cooling water systems above 60 °C [>140 °F] exceed the threshold for SS SCC.	Closed-cycle cooling water, Closed-cycle cooling water >60°C (>140°F)
Concrete	The external environment of components embedded in concrete.	Concrete

Table 3.0-1 Mechanical System Service Environments

NAPS AMR Environment	Definition	NUREG-2191 Environment(s) Used for AMR Comparison [(1)]
Condensation	Condensation on the surfaces of systems with temperatures below the dew point, or in the associated drains. Condensation may be internal or external. Condensation includes the potential for concentration of contaminants. Elastomers in condensation are matched to the GALL-SLR environment of "Air" for loss of material and flow blockage.	Air, Condensation
Diesel exhaust	Gases, fluids, and 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 used for combustion engines may include water contamination. The fuel oil environment does not exceed the threshold temperature for cracking of stainless steel (140°F).	Fuel oil
Gas	Environments of inert or non-reactive gases. Oxygen is not considered to be present in this environment. Gas is used to describe hydrogen, nitrogen, freon, carbon dioxide and halon environments. Reactive replacement gases for freon and halon are not included in this environment.	Gas
Lubricating oil	Lubricating oils are low-to-medium viscosity hydrocarbons, with the possibility of containing contaminants and/or moisture, used for bearing, gear, and engine lubrication. This name is also used to describe non-water based hydraulic fluid (including Fyrquel®, used in the electrohydraulic control system).	Lubricating oil
Petrolatum corrosion preventive casing filler	Petrolatum (petroleum jelly) is used as a corrosion-inhibiting filler in the annular space surrounding a buried, sleeved service water system pipe. Petrolatum provides an excellent barrier to water intrusion and is an excellent anti-foulant.	None
Raw water	Raw, untreated, river, lake, or groundwater. Raw water does not exceed the threshold temperature for SCC of stainless steels (140°F).	Raw water, Raw water (potable)

Table 3.0-1 Mechanical System Service Environments

NAPS AMR Environment	Definition	NUREG-2191 Environment(s) Used for AMR Comparison [(1)]
Reactor coolant	Treated water in the reactor coolant system and connected systems at or near full operating temperature. Reactor coolant includes the steam phase. The Reactor coolant environment name is used for the reactor coolant system, the reactor vessel and internals components. The environment for connected piping and systems may be referred to as one of the treated borated water environments.	Reactor coolant
Reactor coolant >250°C (>482°F)	Water in the reactor coolant system above the thermal embrittlement threshold for CASS. Components in this environment are also matched to GALL-SLR environment items without the temperature threshold for other aging effects.	Reactor coolant, Reactor coolant >250°C (>482°F)
Reactor coolant >250°C (>482°F) and neutron flux	Water in the reactor coolant system above the thermal embrittlement threshold for CASS, and above the fluence threshold for neutron embrittlement.	Reactor coolant and neutron flux
Reactor coolant and neutron flux	Reactor core environment that will result in a neutron fluence exceeding the threshold for management at the end of the subsequent license renewal term. The reactor coolant environment name is used for the reactor vessel and internals components.	Reactor coolant, Reactor coolant and neutron flux
Soil	External environment for components exposed to soil or buried in the soil, including groundwater in the soil. The soil around buried piping at NAPS does not correspond to a “carbonate/bicarbonate environment” identified as applicability criterion for cracking of steel in soil in NUREG-2191, items V.E.E-420, VII.I.A-425, and VIII.H.S-420[(2)].	Soil
Steam	The vapor phase of treated water. Steam may be superheated or saturated.	Steam
Treated borated water	Borated (PWR) water is a controlled water system. The chemical and volume control system maintains the proper water chemistry in the reactor coolant system while adjusting the boron concentration during operation to match long-term reactivity changes in the core.	Treated borated water

Table 3.0-1 Mechanical System Service Environments

NAPS AMR Environment	Definition	NUREG-2191 Environment(s) Used for AMR Comparison (1)
Treated borated water >60°C (>140°F)	Treated water with boric acid in PWR systems above the 60°C [>140°F] SCC threshold for stainless steel.	Treated borated water, Treated borated water >60°C (>140°F)
Treated water	Treated water is demineralized water. Treated water could be deaerated and include corrosion inhibitors, biocides, other additives such as glycol, or some combination of these treatments. This environment may represent liquid or steam/vapor.	Secondary feedwater, Treated water
Treated water >60°C (>140°F)	Treated water above the 60°C (140°F) stress corrosion cracking threshold for stainless steel. This environment may represent liquid or steam/vapor. Components in this environment are also matched to GALL-SLR environment items without the temperature threshold for other aging effects.	Secondary feedwater System temperature up to 340°C (644°F), Treated water, Treated water >60°C (>140°F)
Underground	Underground piping and tanks are 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 (e.g., special lifting equipment is required to gain access to the vault). When the underground environment is cited, the term includes exposure to air-outdoor, air-indoor uncontrolled, air, raw water, groundwater, and condensation.	Underground
Waste water	Radioactive, potentially radioactive, or non-radioactive waters that are collected from equipment and floor drains. Waste waters may contain contaminants, including oil and boric acid, as well as originally treated water that is not monitored by a chemistry program.	Waste water
Waste water >60°C (>140°F)	Waste water above 60°C [>140°F] exceeds the threshold for SS SCC.	Waste water, Waste water >60°C (>140°F)

Note:

1. NUREG-2191 items with environments of “Any” are cited where applicable, and environment equivalences are not listed in this table.
2. Carbonate/bicarbonate environment is not applicable based on pH of soil samples compared to threshold of pH 9.3 specified in Table 4.1 of OPS TTO8, “Stress Corrosion Cracking Study.”

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3.1 AGING MANAGEMENT OF REACTOR VESSEL, INTERNALS, AND REACTOR COOLANT SYSTEM

3.1.1 INTRODUCTION

This section provides the results of the aging management review for those components identified in Section 2.3.1, Reactor Vessel, Internals, and Reactor Coolant System, as being subject to aging management review. The systems, or portions of systems, which are addressed in this section are described in the indicated sections.

- Reactor Vessel (Section 2.3.1.1)
- Reactor Vessel Internals (Section 2.3.1.2)
- Reactor Coolant (Section 2.3.1.3)
- Steam Generator (Section 2.3.1.4)

3.1.2 RESULTS

The following table summarizes the results of the aging management review for the Reactor Vessel, Internals, and Reactor Coolant System.

- Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation
- Table 3.1.2-2 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel Internals - Aging Management Evaluation
- Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation
- Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator - Aging Management Evaluation

3.1.2.1 MATERIALS, ENVIRONMENTS, AGING EFFECTS REQUIRING MANAGEMENT AND AGING MANAGEMENT PROGRAMS

3.1.2.1.1 Reactor Vessel

Materials

The materials of construction for the reactor vessel subcomponents are:

- Cast austenitic stainless steel
- High-strength steel
- Nickel alloy
- Stainless steel
- Steel
- Steel with stainless steel cladding

Environment

The reactor vessel subcomponents are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Reactor coolant
- Reactor coolant >250°C (>482°F)
- Reactor coolant and neutron flux

Aging Effects Requiring Management

The following aging effects, associated with the reactor vessel subcomponents, require management:

- Crack growth
- Cracking
- Cumulative fatigue damage
- Loss of fracture toughness
- Loss of material

Aging Management Programs

The following aging management programs manage the aging effects for the reactor vessel subcomponents:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)
- Boric Acid Corrosion (B2.1.4)
- Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Neutron Fluence Monitoring (B3.2)
- One-Time Inspection (B2.1.20)
- Reactor Head Closure Stud Bolting (B2.1.3)
- Reactor Vessel Material Surveillance (B2.1.19)
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B2.1.6)
- Water Chemistry (B2.1.2)

3.1.2.1.2 Reactor Vessel Internals

Materials

The materials of construction for the reactor vessel internals subcomponents are:

- Cast austenitic stainless steel
- Nickel alloy
- Stainless steel
- Stellite™

Environment

The reactor vessel internals subcomponents are exposed to the following environments:

- Reactor coolant >250°C (>482°F) and neutron flux
- Reactor coolant and neutron flux

Aging Effects Requiring Management

The following aging effects, associated with the reactor vessel internals subcomponents, require management:

- Changes in dimensions
- Cracking
- Cumulative fatigue damage
- Loss of fracture toughness
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the reactor vessel internals subcomponents:

- Flux Thimble Tube Inspection (B2.1.24)
- PWR Vessel Internals (B2.1.7)
- Water Chemistry (B2.1.2)

3.1.2.1.3 Reactor Coolant

Materials

The materials of construction for the reactor coolant system component types are:

- Cast austenitic stainless steel
- Copper alloy
- Copper alloy (>15% Zn)
- Fiberglass
- Glass
- Nickel alloy
- Stainless steel
- Steel
- Steel with internal coating
- Steel with stainless steel cladding

Environment

The reactor coolant system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air with borated water leakage
- Closed–cycle cooling water
- Concrete
- Gas
- Lubricating oil
- Reactor coolant
- Reactor coolant >250°C (>482°F)
- Treated borated water
- Treated borated water >60°C (>140°F)
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the reactor coolant system, require management:

- Cracking
- Cumulative fatigue damage
- Flow blockage
- Loss of coating or lining integrity
- Loss of fracture toughness
- Loss of material
- Loss of preload
- Reduced thermal insulation resistance
- Reduction of heat transfer

Aging Management Programs

The following aging management programs manage the aging effects for the reactor coolant system component types:

- ASME Code Class 1 Small-Bore Piping (B2.1.22)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)
- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- Compressed Air Monitoring (B2.1.14)
- Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Structures Monitoring (B2.1.34)
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B2.1.6)
- Water Chemistry (B2.1.2)

3.1.2.1.4 Steam Generator

Materials

The materials of construction for the steam generator subcomponents are:

- Nickel alloy
- Stainless steel
- Steel
- Steel with nickel alloy cladding
- Steel with stainless steel cladding

Environment

The steam generator subcomponents are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Reactor coolant
- Steam
- Treated water
- Treated water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects, associated with the steam generator subcomponents, require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload
- Reduction of heat transfer
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the steam generator subcomponents:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)
- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- One-Time Inspection (B2.1.20)
- Steam Generators (B2.1.10)
- Water Chemistry (B2.1.2)

3.1.2.2 FURTHER EVALUATION OF AGING MANAGEMENT AS RECOMMENDED BY NUREG-2192

NUREG-2192 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the Subsequent License Renewal Application. For the reactor vessel, internals, and reactor coolant system, those evaluations are addressed in the following sections.

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 is an aging effect assessed by a fatigue time-limited aging analysis (TLAA).

[3.1.1-001] – The evaluation of fatigue is a TLAA for steel reactor vessel closure head stud, nut and washer exposed to air-indoor uncontrolled in the Reactor Vessel, Internals, and Reactor Coolant System, and is discussed in Section 4.3.2.4, Reactor Vessel.

[3.1.1-002] – The evaluation of fatigue is a TLAA for nickel alloy steam generator components exposed to reactor coolant or steam in the Reactor Vessel, Internals, and Reactor Coolant System, and is discussed in Section 4.3.2.5, Steam Generators (including Unit 1 Inlet Nozzle SWOLs).

[3.1.1-003] – The evaluation of fatigue is a TLAA for stainless steel reactor vessel internal components exposed to reactor coolant and neutron flux in the Reactor Vessel, Internals, and Reactor Coolant System, and is discussed in Section 4.3.5, Reactor Vessel Internals Fatigue Analyses.

[3.1.1-005] – The evaluation of fatigue is a TLAA for steel or stainless steel steam generator components in the Reactor Vessel, Internals, and Reactor Coolant System, and is discussed in Section 4.3.2.5, Steam Generators (including Unit 1 Inlet Nozzle SWOLs).

[3.1.1-008] – The evaluation of fatigue is a TLAA for stainless steel, steel (with nickel alloy or stainless steel cladding) or nickel alloy steam generator components exposed to reactor coolant in the Reactor Vessel, Internals, and Reactor Coolant System, and is discussed in Section 4.3.2.5, Steam Generators (including Unit 1 Inlet Nozzle SWOLs).

[3.1.1-009] – The evaluation of fatigue is a TLAA for stainless steel or steel (with stainless steel cladding) reactor coolant pressure boundary components exposed to reactor coolant in the Reactor Vessel, Internals, and Reactor Coolant System, and in Auxiliary Systems, and is discussed in Section 4.3.1, Transient Cycle Projections for 80 years. The evaluation of fatigue is a TLAA for stainless steel reactor coolant system primary loop piping, and is discussed in Section 4.3.3, USAS (ANSI) B31.1 Allowable Stress Analyses, Section 4.3.6, High-Energy Line Break Analysis, and in Section 4.7.3, Leak-Before-Break.

[3.1.1-010] – The evaluation of fatigue is a TLAA for steel (with stainless steel cladding), stainless steel, or nickel alloy reactor vessel components exposed to reactor coolant in the Reactor Vessel, Internals, and Reactor Coolant System, and is discussed in Section 4.3.2.4, Reactor Vessel.

[3.1.1-011] – The evaluation of fatigue is a TLAA for steel pump and valve closure bolting exposed to high temperatures and thermal cycles in the Reactor Vessel, Internals, and Reactor Coolant System, and is discussed in Section 4.3.2, ASME Code, Section III, Class 1 Fatigue Analyses.

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).

(1) [3.1.1-012] – Loss of material due to general, pitting, and crevice corrosion could occur in the steel PWR steam generator upper and lower shell and transition cone exposed to secondary feedwater and steam. The steam generator periodic inspections performed as required by the inservice inspection (ISI) program have revealed no significant degradation. However, Information Notice 90-04, “Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators,” stated that volumetric examinations (UT) of the shell-to-transition-cone girth welds, required by Section XI of the ASME Code, may not be sufficient to differentiate isolated cracks from inherent geometric conditions. For the girth welds, a one-time inspection will 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. The One-Time Inspection (B2.1.20) program will perform a magnetic particle test (MT) inspection of the upper shell-to-transition cone girth weld on each steam generator (essentially 100 percent examination coverage of each weld), prior to the subsequent period of extended operation. This one-time inspection, along with the continued implementation of the Water Chemistry (B2.1.2) program and the steam generator periodic inspections required by the ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program will effectively manage loss of material for the steam generator upper and lower shell and transition cone exposed to secondary feedwater and steam prior to loss of intended function.

(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.

(2) [3.1.1-012] – Loss of material due to general, pitting, and crevice corrosion could result in the steel PWR steam generator shell assembly exposed to secondary feedwater and steam. The lower shell assemblies of the steam generators have been replaced for NAPS Units 1 and 2, generating a cut in the middle of the transition cone and consequently creating a new transition cone closure weld. For this new transition cone closure weld, 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. The One-Time Inspection (B2.1.20) program will perform a magnetic particle test (MT) inspection of a continuous circumferential transition cone closure weld, on each steam generator (essentially 100 percent examination coverage of each weld), prior to the subsequent period of extended operation. This one-time inspection along with the continued implementation of the Water Chemistry (B2.1.2) program and the steam generator periodic inspections required by the ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program will effectively manage loss of material for the steel steam generator shell assembly exposed to secondary feedwater and steam prior to loss of intended function.

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.

(1) [3.1.1-013] – Neutron irradiation embrittlement is a TLAA as defined in 10 CFR 54.3 and is evaluated 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."'

(2) [3.1.1-014] – Loss of fracture toughness due to neutron irradiation embrittlement could occur in the reactor vessel shell, primary nozzle, and support pad. The Reactor Vessel Material Surveillance (B2.1.19) program and the Neutron Fluence Monitoring (B3.2) program monitor neutron irradiation embrittlement of the reactor vessel.

(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.

(3) Not applicable. This further evaluation item is applicable to Babcock & Wilcox reactor internals only.

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.

(1) 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).

(2) 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. Tor CLBs that include these types of evaluations, the evaluations may need to be identified as TLAAs if they are determined to conform to the six criteria for defining TLAAs in 10 CFR 54.3(a). The methodology for evaluating the underclad flaw should be consistent with the flaw evaluation procedure and criterion in the ASME Code, Section XI. 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).

[3.1.1-018] – Reactor vessel underclad cracking is a TLAA as defined in 10 CFR 54.3 and is addressed in Section 4.7.7, Cracking Associated with Weld Deposited Cladding.

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).

(1) [3.1.1-019] – Cracking due to SCC could occur in PWR stainless steel bottom-mounted instrument guide tubes exposed to reactor coolant. Mitigation and monitoring of cracking of the bottom-mounted instrument guide tubes are managed by the Water Chemistry (B2.1.2) program and the ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program respectively. The Water Chemistry (B2.1.2) program provides controls to minimize the presence of contaminants that promote SCC. The ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program, relies on VT-2 examinations to identify and evaluate the degradation of bottom-mounted instrumentation guide tubes (external to bottom head) to ensure that there is no loss of intended function.

(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).

(2) [3.1.1-020] – Cracking due to SCC could occur in Class 1 PWR cast austenitic stainless steel reactor coolant system piping and piping components exposed to reactor coolant. NAPS applicable components are the reactor coolant loop piping and fittings. Most cast austenitic stainless steel reactor coolant loop piping and fittings are consistent with the NUREG-0313 guidelines with regard to ferrite and carbon content as verified by certified material test reports. Mitigation and monitoring of cracking of the reactor coolant loop piping and fittings are managed by the Water Chemistry (B2.1.2) program, and the ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program, respectively. The Water Chemistry (B2.1.2) program provides controls to minimize the presence of contaminants that promote SCC. The ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program is the plant-specific program that provides for periodic testing and inspections to detect cracking.

(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.

(3) [3.1.1-139] – Cracking due to SCC could occur in stainless steel or nickel alloy reactor vessel flange leak detection lines of PWR light-water reactor facilities.

The reactor vessel flange leakage monitor tube at NAPS is made of nickel alloy and the vessel flange leakage detection line piping is stainless steel. A review of NAPS operating experience revealed that cracking and pitting were identified on the Unit 2 stainless steel leakage detection line in October 2011. After removal and replacement, analysis concluded that the cracking initiated on the internal surface of the line and propagated to the external surface (approximately one third of the circumference) where it was detected. Analysis further concluded that the intermittent use of this line, resulting in alternate wetting (by reactor coolant leakage) and drying, created conditions favorable for a concentration of contaminates. Therefore, the External Surfaces Monitoring of Mechanical Components (B2.1.23) program will manage cracking on the external surfaces of the reactor vessel flange leakage monitor tube and the vessel flange leakage detection line piping exposed to air-indoor uncontrolled.

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).

The NAPS steam generators do not have feedwater impingement plates and associated supports. Therefore, this item is not applicable.

3.1.2.2.9 Aging Management of Pressurized Water 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), provides the industry's current aging management recommendations for the reactor vessel internal (RVI) components that are included in the design of a PWR facility. In this report, the EPRI Materials Reliability Program identified that the following aging mechanisms may be applicable to the design of the RVI components in these types of facilities: (a) SCC, (b) irradiation-assisted stress corrosion cracking (IASCC), (c) fatigue, (d) wear, (e) neutron irradiation embrittlement, (f) thermal aging embrittlement, (g) void swelling and irradiation growth, or (h) thermal or irradiation-enhanced stress relaxation or irradiation enhanced creep. The methodology in MRP-227-A was approved by the NRC in a safety evaluation dated December 16, 2011 (ADAMS Accession No. ML11308A770), which includes those plant specific applicant/licensee action items that a licensee or applicant applying the MRP-227-A report would need to address and resolve and apply to its licensing basis.

The EPRI MRP's functionality analysis and failure modes, effects, and criticality analysis bases for grouping Westinghouse-designed, B&W-designed and Combustion Engineering (CE)-designed RVI components into these inspection categories was based on an assessment of aging effects and relevant time-dependent aging parameters through a cumulative 60-year licensing period (i.e., 40 years for the initial operating license period plus an additional 20 years during the initial period of extended operation). The EPRI MRP has not assessed whether operation of Westinghouse-designed, B&W designed and CE designed reactors during an SLR operating period would have any impact on the existing susceptibility rankings and inspection categorizations for the RVI components in these designs, as defined in MRP-227-A or its applicable MRP background documents (e.g., MRP-191 for Westinghouse-designed or CE designed RVI components or MRP-189 for B&W designed components).

As described in GALL-SLR Report AMP XI.M16A, the applicant may use the MRP-227-A based AMP as an initial reference basis for developing and defining the AMP that will be applied to the RVI components for the subsequent period of extended operation. However, to use this alternative basis, GALL-SLR Report AMP XI.M16A recommends that the MRP-227-A based AMP be enhanced to include a gap analysis of the components that are within the scope of the AMP. The gap analysis is a basis for identifying and justifying any potential changes to the MRP-227-A based program that may be necessary to provide reasonable assurance that the effects of age related degradation will be managed during the subsequent period of extended operation. The criteria for the gap analysis are described in GALL-SLR Report AMP XI.M16A.

Alternatively, the PWR SLRA may define a plant-specific AMP for the RVI components to demonstrate that the RVI components will be managed in accordance with the requirements of 10 CFR 54.21(a)(3) during the proposed subsequent period of extended operation. Components to be inspected, parameters monitored, monitoring methods, inspection sample size, frequencies, expansion criteria, and acceptance criteria are justified in the SLRA. The NRC staff will assess the adequacy of the plant-specific AMP against the criteria for the 10 AMP program elements that are defined in Section A.1.2.3 of SRP-SLR Appendix A.1.

[3.1.1-028] [3.1.1-053a] [3.1.1-053b] [3.1.1-053c] [3.1.1-055c] [3.1.1-059a] [3.1.1-059b] [3.1.1-059c] – Electric Power Research Institute (EPRI) Topical Report (TR)-1022863, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A)" provides the industry's current aging management recommendations for the reactor vessel internal (RVI) components that are included in the design of a PWR facility. The methodology in MRP-227-A was approved by the NRC in a safety evaluation dated December 16, 2011, which includes those plant-specific applicant/licensee action items that a licensee or applicant applying the MRP-227-A report would need to address and resolve and apply to its licensing basis. The approved MRP-227-A guidelines are based on an analysis of the reactor vessel internals that considers the operating conditions up to a 60-year operating period. To address an 80-year operating period, the guidelines have been supplemented with a gap analysis that identifies enhancements to the PWR Vessel Internals (B2.1.7) program. The MRP-227-A Gap Analysis for PWR Vessel Internals Aging Management provides a basis for identifying and justifying changes to the MRP-227-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 PWR Vessel Internals (B2.1.7) program manages the applicable aging effects for the reactor vessel internal components and the Water Chemistry (B2.1.2) program monitors and controls water environments consistent with industry guidelines to ensure that the reactor coolant water environment is favorable to mitigate SCC in RVI components.

3.1.2.2.10 Loss of Material Due to Wear

(1) Industry OE indicates that loss of material due to wear can occur in PWR control rod drive (CRD) head penetration nozzles made of nickel alloy due to the interactions between the nozzle and the thermal sleeve centering pads of the nozzle (see Ref. 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).

(1) [3.1.1-116] – Loss of material due to wear can occur in PWR control rod drive head penetration nozzles made of nickel alloy due to the interaction between the nozzle and the thermal sleeve centering pads of the nozzle. The head penetration nozzles are also called control rod drive mechanism housing (head adapter) tubes.

The ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program includes inspection of the control rod drive head penetration nozzles for loss of material due to wear.

(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 describe in Ref. 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.

(2) Loss of material due to wear for stainless steel control rod drive penetration nozzle thermal sleeves is addressed by 3.1.2.2.9.

3.1.2.2.11 Cracking due to Primary Water Stress Corrosion Cracking

(1) Foreign OE in steam generators with a design similar to that of Westinghouse steam generators (particularly Model 51) has identified cracks due to primary water stress corrosion cracking (PWSCC) in steam generator (SG) divider plate assemblies fabricated of Alloy 600 and/or the associated Alloy 600 weld materials, even with proper primary water chemistry. Cracks have been detected in the stub runner with depths typically about 0.08 inches (EPRI 3002002850).

All but one of these instances of cracking has been detected in divider plate assemblies that are approximately 1.3 inches in thickness. For the cracks in the 1.3-inch thick divider plate assemblies, the cracks tend to be parallel to the divider-plate-to-stub-runner weld (i.e., run horizontally in parallel to the lower surface of the tubesheet). For the one instance of cracking in a divider plate assembly with a thickness greater than 1.3 inches, the cracking occurred in a divider plate assembly with a thickness of approximately 2.4 inches near manufacturing marks on the upper end of the stub runner used for locating tubesheet holes. These flaws were estimated to be approximately 0.08-inch deep.

Although these instances indicate that the water chemistry program may not be sufficient to manage cracking due to PWSCC in SG divider plate assemblies, analyses by the industry indicate that PWSCC in the divider plate assembly does not pose a structural integrity concern for other steam generator components (e.g., tubesheet and tube-to-tubesheet welds) and does not adversely affect other safety analyses (e.g., analyses supporting tube plugging and repairs, tube repair criteria, and design basis accidents). In addition, the industry analyses indicate that flaws in the divider plate assembly will not adversely affect the heat transfer function (as a result of bypass flow) during normal forced flow operation, during natural circulation conditions (assessed in the analyses of various design basis accidents), or in the event of a loss-of-coolant accident (LOCA).

Furthermore, additional industry analyses indicate that PWSCC in the divider plate assembly is unlikely to adversely impact adjacent items, such as the tubesheet cladding, tube-to-tubesheet welds, and channel head. Therefore,

•For units with divider plate assemblies fabricated of Alloy 690 and Alloy 690 type weld materials, a plant-specific AMP is not necessary.

•For units with divider plate assemblies fabricated of Alloy 600 or Alloy 600 type weld materials, if the analyses performed by the industry (EPRI 3002002850) are applicable and bounding for the unit, a plant-specific AMP is not necessary.

•For units with divider plate assemblies fabricated of Alloy 600 or Alloy 600 type weld materials, if the industry analyses (EPRI 3002002850) are not bounding for the applicant's unit, a plant-specific AMP is necessary or a rationale is necessary for why such a program is not needed. A plant-specific AMP (one beyond the primary water chemistry and the steam generator programs) may include a one time inspection that is capable of detecting cracking to verify the effectiveness of the water chemistry and steam generator programs and the absence of PWSCC in the divider plate assemblies.

The existing programs rely on control of reactor water chemistry to mitigate cracking due to PWSCC and general visual inspections of the channel head interior surfaces (included as part of the steam generator program). The GALL-SLR Report recommends further evaluation for a plant-specific AMP to confirm the effectiveness of the primary water chemistry and steam generator programs as described in this section. Acceptance criteria for a plant-specific AMP are described in BTP RLSB-1 (Appendix A.1 of this SRP SLR). In place of a plant-specific AMP, the applicant may provide a rationale to justify why a plant-specific AMP is not necessary.

(1) [3.1.1-025] – 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.

NAPS steam generator (Westinghouse Model 54F) divider plates and associated welds are fabricated of Alloy 600 materials for Unit 1 and Alloy 690 for Unit 2. For Unit 2, a plant-specific AMP is not necessary.

An analysis performed by the industry (EPRI 3002002850) evaluated divider plate cracking for the Westinghouse Model 51 steam generator, which was determined to be the most limiting steam generator model. In a letter to the industry dated October 10, 2016, EPRI provided a checklist to determine whether this analysis bounds an applicant's steam generators. This checklist was completed for NAPS and documents that the analysis is applicable and bounding for the NAPS Unit 1 steam generators; therefore, a plant-specific AMP is not necessary.

Cracking of the NAPS steam generator channel head divider plate is managed by the Steam Generators (B2.1.10) program and the Water Chemistry (B2.1.2) program.

(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.

(2) [3.1.1-025] – Cracking due to PWSCC could occur in steam generator nickel alloy tube-to-tubesheet welds exposed to reactor coolant.

NAPS steam generators have thermally treated Alloy 690 tubes and the tubesheets are clad using Alloy 600 type material.

The analysis performed by the industry (EPRI 3002002850) evaluated PWSCC in nickel alloy tube-to-tubesheet welds for the Westinghouse Model 51 steam generator, which was determined to be the most limiting steam generator model. In a letter to the industry dated October 10, 2016, EPRI provided a checklist to determine whether this analysis bounds an applicant's steam generators. This checklist was completed for NAPS and documents that the analysis is applicable and bounding for the NAPS steam generators (Westinghouse Model 54F); and visual inspections of the tubesheet region looking for evidence of cracking are performed as part of the Steam Generators (B2.1.10) program. Therefore, a plant-specific AMP is not necessary.

Cracking of the NAPS steam generator tube-to-tubesheet welds exposed to reactor coolant is managed by the Steam Generators (B2.1.10) program and the Water Chemistry (B2.1.2) program.

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.

[3.1.1-105] – Loss of material of steel with an external environment of concrete is not an applicable aging effect for components in the reactor coolant system. A portion of the outside diameter of each steel neutron shield tank is encased in concrete that conforms to ACI 318, "Building Code Requirements for Structural Concrete." Review of NAPS operating experience did not identify degradation of concrete around embedded components that could lead to penetration of water, and the tanks are not potentially exposed to groundwater. No other steel piping components in the Reactor Vessel, Internals, and Reactor Coolant System are exposed to concrete.

3.1.2.2.16 Loss of Material Due to Pitting and Crevice Corrosion

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 atmospheric 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.

[3.1.1-136] – Loss of material due to pitting and crevice corrosion could occur in stainless steel and nickel alloy piping, piping components, and tanks exposed to any air environment.

Except for the reactor vessel leakage monitor tube and leakage detection line piping described in 3.1.2.2.6.3, a review of NAPS operating experience did not reveal a history of pitting or crevice corrosion of stainless steel and nickel alloy components exposed to an external air-indoor uncontrolled environment, and a one-time inspection will demonstrate that loss of material is not occurring. Loss of material of the nickel alloy reactor vessel leakage monitor tube and the stainless steel leakage detection line piping exposed to air-indoor uncontrolled is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program. For other stainless steel and nickel alloy components of the Reactor Vessel, Internals, and Reactor Coolant System exposed to air-indoor uncontrolled, loss of material is managed by the One-Time Inspection (B2.1.20) program.

3.1.2.2.17 Quality Assurance for Aging Management of Nonsafety-Related Components

Quality Assurance provisions applicable to subsequent license renewal are discussed in Appendix B1.3, Quality Assurance Program and Administrative Controls.

3.1.2.2.18 Ongoing Review of Operating Experience

The operating experience process and acceptance criteria are described in Appendix B1.4, Operating Experience.

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Results Tables: Reactor Vessel, Internals, and Reactor Coolant System

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-001	Steel reactor vessel closure flange assembly components exposed to air-indoor uncontrolled	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 Metal Fatigue	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of steel reactor vessel closure flange assembly components exposed to air-indoor uncontrolled is a TLAA. See further evaluation 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 components exposed to reactor coolant or secondary feedwater/steam is a TLAA. See further evaluation 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 components exposed to reactor coolant and neutron flux is a TLAA. See further evaluation 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. NAPS has no in-scope steel pressure vessel support skirt and attachment welds in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
3.1.1-005	Steel, stainless steel, steel (with stainless steel or nickel alloy cladding) steam generator components, pressurizer relief tank components, piping components, bolting	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 Metal Fatigue	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of steel or stainless steel components is a TLAA. See further evaluation in Section 3.1.2.2.1.
3.1.1-006	Stainless steel, steel (with or without nickel alloy or stainless steel cladding), nickel alloy reactor coolant pressure boundary components: 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)	Not applicable - BWR only.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-007	Stainless steel, steel (with or without nickel alloy or stainless steel cladding), nickel alloy reactor vessel components: nozzles; penetrations; 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)	Not applicable - BWR only.
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 nickel alloy or stainless steel cladding) or nickel alloy steam generator components exposed to reactor coolant is a TLAA. See further evaluation 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 or steel (with stainless steel cladding) reactor coolant pressure boundary components exposed to reactor coolant is a TLAA. In addition to Reactor Vessel, Internals, and Reactor Coolant System, components in the Auxiliary Systems (chemical and volume control, and sampling system) are aligned to this item. See further evaluation in Section 3.1.2.2.1.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-010	Steel (with or without nickel alloy or stainless steel cladding), stainless steel, or nickel alloy reactor vessel components: nozzles; penetrations; pressure housings; safe ends; thermal sleeves; vessel shells, heads and welds exposed to reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 Metal Fatigue	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of steel with stainless steel cladding, stainless steel, or nickel alloy reactor vessel components exposed to reactor coolant is a TLAA. See further evaluation in Section 3.1.2.2.1.
3.1.1-011	Steel or stainless steel pump and valve closure bolting exposed to high temperatures and thermal cycles	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 Metal Fatigue	Yes (SRP-SLR Section 3.1.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of steel pump and valve closure bolting exposed to high temperatures and thermal cycles is a TLAA. See further evaluation 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 Code, 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 with an additional program for the upper shell-to-transition cone girth weld and for the transition cone closure weld. The One-Time Inspection (B2.1.20) program will verify the effectiveness of the Water Chemistry (B2.1.2) program to manage loss of material for the upper shell-to-transition cone girth weld and for the transition cone closure weld. See further evaluation 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 of steel (with stainless steel cladding) reactor vessel components exposed to reactor coolant and neutron flux is a TLAA. See further evaluation in Section 3.1.2.2.3.1.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-014	Steel (with or without cladding) reactor vessel beltline shell, nozzle, and weld components; exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement	AMP XI.M31, Reactor Vessel Material Surveillance, and X.M2, Neutron Fluence Monitoring	Yes (SRP-SLR Section 3.1.2.2.3.2)	Consistent with NUREG-2191. See further evaluation in Section 3.1.2.2.3.2.
3.1.1-015	Stainless steel Babcock & Wilcox (including CASS, martensitic SS, and PH SS) and nickel alloy reactor vessel internal components exposed to reactor coolant and neutron flux	Reduction in fracture toughness due to neutron irradiation	TLAA, SRP-SLR Section 4.7 Other Plant-Specific TLAAs	Yes (SRP-SLR Section 3.1.2.2.3.3)	Not applicable. NAPS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.
3.1.1-016	Stainless steel or nickel alloy reactor vessel top head enclosure flange leakage detection line exposed to air-indoor uncontrolled, reactor coolant leakage	Cracking due to SCC, IGSCC	AMP XI.M32, One-Time Inspection, or AMP XI.M36, External Surfaces Monitoring of Mechanical Components	Yes (SRP-SLR Section 3.1.2.2.4.1)	Not applicable - BWR only.
3.1.1-017	Stainless steel isolation condenser components exposed to reactor coolant	Cracking due to SCC, IGSCC	AMP XI.M1, ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and AMP XI.M2, Water Chemistry	Yes (SRP-SLR Section 3.1.2.2.4.2)	Not applicable - BWR only.
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)	Consistent with NUREG-2191. Crack growth due to cyclic loading of reactor vessel shell fabricated of SA508-Cl 2 forgings clad with stainless steel using a high-heat-input welding process exposed to reactor coolant is a TLAA. See further evaluation in Section 3.1.2.2.5.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-019	Stainless steel reactor vessel bottom-mounted instrument guide tubes (external to reactor vessel) exposed to reactor coolant	Cracking due to SCC	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.6.1)	Consistent with NUREG-2191. Cracking of stainless steel reactor vessel bottom-mounted instrument guide tubes (external to reactor vessel) exposed to reactor coolant is managed by the ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program and the Water Chemistry (B2.1.2) program. See further evaluation 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. Cracking of cast austenitic stainless steel Class 1 piping, piping components exposed to reactor coolant is managed by the ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program and the Water Chemistry (B2.1.2) program. See further evaluation in Section 3.1.2.2.6.2.
3.1.1-021	Steel and stainless steel isolation condenser components exposed to reactor coolant	Cracking due to cyclic loading	AMP XI.M1, ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Yes (SRP-SLR Section 3.1.2.2.7)	Not applicable - BWR only.
3.1.1-022	Steel steam generator feedwater impingement plate and support exposed to secondary feedwater	Loss of material due to erosion	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.8)	Not applicable. NAPS has no in-scope steel steam generator feedwater impingement plate and support exposed to secondary feedwater in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
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. A plant-specific program is not needed for the divider plate or for the tube-to-tubesheet weld. See further evaluation in Section 3.1.2.2.11.1 and 3.1.2.2.11.2.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-028	Existing Programs components: Stainless steel, nickel alloy Westinghouse control rod guide tube support pins, and Combustion Engineering thermal shield positioning pins; Zircaloy-4 Combustion Engineering incore instrumentation thimble tubes exposed to reactor coolant and neutron flux	Loss of material due to wear; cracking due to SCC, irradiation-assisted SCC, fatigue	AMP XI.M16A, PWR Vessel Internals, and AMP XI.M2, Water Chemistry (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. This item is applied to loss of material for the nickel alloy clevis insert bolt and dowel exposed to reactor coolant and neutron flux. Cracking for these components are addressed by row 3.1.1-053c. See further evaluation in Section 3.1.2.2.9.
3.1.1-029	Nickel alloy core shroud and core plate access hole cover (welded covers) exposed to reactor coolant	Cracking due to SCC, IGSCC, irradiation-assisted SCC	AMP XI.M9, BWR Vessel Internals, and AMP XI.M2, Water Chemistry	Yes (SRP-SLR Section 3.1.2.2.12)	Not applicable - BWR only.
3.1.1-030	Stainless steel, nickel alloy penetration: drain line exposed to reactor coolant	Cracking due to SCC, IGSCC, cyclic loading	AMP XI.M1, ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and AMP XI.M2, Water Chemistry (SCC, IGSCC mechanisms only)	No	Not applicable - BWR only.
3.1.1-031	Steel and stainless steel isolation condenser components exposed to reactor coolant	Loss of material due to general (steel only), pitting, crevice corrosion, wear	AMP XI.M1, ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and AMP XI.M2, Water Chemistry	No	Not applicable - BWR only.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-032	Stainless steel, nickel alloy, or CASS reactor vessel internals, core support structure (not already referenced as ASME Code, Section XI Examination Category B-N-3 core support structure components in MRP-227-A), exposed to reactor coolant and neutron flux	Cracking, loss of material due to wear	AMP XI.M1, ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Not applicable. NAPS has no in-scope stainless steel, nickel alloy, or CASS reactor vessel internals or core support structure (not already referenced as ASME Code, Section XI Examination Category B-N-3 core support structure components in MRP-227-A), exposed to reactor coolant and neutron flux in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
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 Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and AMP XI.M2, Water Chemistry	No	Consistent with NUREG-2191 and a different aging management program is credited for some components. The Steam Generators (B2.1.10) program will manage cracking of the steam generator channel head instead of the ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program. In addition to Reactor Vessel, Internals, and Reactor Coolant System, components in the Engineered Safety Features (residual heat removal and safety injection) and Auxiliary Systems (chemical and volume control and sampling system) are aligned to this row.
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 Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and AMP XI.M2, Water Chemistry	No	Not applicable. NAPS has no in-scope 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) in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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 Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Consistent with NUREG-2191.
3.1.1-036	Steel, stainless steel pressurizer integral support exposed to any environment	Cracking due to cyclic loading	AMP XI.M1, ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Consistent with NUREG-2191.
3.1.1-037	Steel reactor vessel flange	Loss of material due to wear	AMP XI.M1, ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Consistent with NUREG-2191.
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 Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Consistent with NUREG-2191.
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 Code, 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. In addition to Reactor Vessel, Internals, and Reactor Coolant System, components in the Engineered Safety Features (safety-injection) and Auxiliary Systems (chemical and volume control) are aligned to this item.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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 Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Consistent with NUREG-2191.
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 Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and AMP XI.M2, Water Chemistry	No	Consistent with NUREG-2191.
3.1.1-041	Nickel alloy core shroud and core plate access hole cover (mechanical covers) exposed to reactor coolant	Cracking due to SCC, IGSCC, irradiation-assisted SCC	AMP XI.M9, BWR Vessel Internals, and AMP XI.M2, Water Chemistry	Yes (SRP-SLR Section 3.1.2.2.12)	Not applicable - BWR only.
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 Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and AMP XI.M2, Water Chemistry	No	Consistent with NUREG-2191.
3.1.1-043	Stainless steel and nickel alloy reactor vessel internals exposed to reactor coolant	Loss of material due to pitting, crevice corrosion	AMP XI.M1, ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and AMP XI.M2, Water Chemistry	No	Not applicable - BWR only.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-044	Steel steam generator secondary manway and handhole cover seating surfaces exposed to treated water, steam	Loss of material due to erosion	AMP XI.M1, ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Consistent with NUREG-2191.
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 Code, 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.
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 Code, 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.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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 Code, Section XI Inservice Inspection, Subsections IWB, IWC and IWD, and AMP XI.M2, Water Chemistry	No	Consistent with NUREG-2191.
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.
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.
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 °F (>482 °C)	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. Additionally, thermal embrittlement of cast austenitic stainless steel reactor coolant pump casings is a TLAA, evaluated in Section 4.7.6, Reactor Coolant Pump Code Case N-481.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-051a	Stainless steel, nickel alloy Babcock & Wilcox reactor internal Primary components exposed to reactor coolant, neutron flux	Cracking due to SCC, irradiation-assisted SCC, fatigue	AMP XI.M16A, PWR Vessel Internals, and AMP XI.M2, Water Chemistry (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. NAPS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.
3.1.1-051b	Stainless steel, nickel alloy Babcock & Wilcox reactor internal Expansion components exposed to reactor coolant, neutron flux	Cracking due to SCC, irradiation-assisted SCC, fatigue, overload	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. NAPS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.
3.1.1-052a	Stainless steel, nickel alloy Combustion Engineering reactor internal Primary components exposed to reactor coolant, neutron flux	Cracking due to SCC, irradiation-assisted SCC, fatigue	AMP XI.M16A, PWR Vessel Internals, and AMP XI.M2, Water Chemistry (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. NAPS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.
3.1.1-052b	Stainless steel, nickel alloy Combustion Engineering reactor internal Expansion components exposed to reactor coolant, neutron flux	Cracking due to SCC, irradiation-assisted SCC, fatigue	AMP XI.M16A, PWR Vessel Internals, and AMP XI.M2, Water Chemistry (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. NAPS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.
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, irradiation-assisted SCC, fatigue	AMP XI.M16A, PWR Vessel Internals, and AMP XI.M2, Water Chemistry (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. NAPS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.
3.1.1-053a	Stainless steel, nickel alloy Westinghouse reactor internal Primary components exposed to reactor coolant, neutron flux	Cracking due to SCC, irradiation-assisted SCC, fatigue	AMP XI.M16A, PWR Vessel Internals, and AMP XI.M2, Water Chemistry (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. See further evaluation in Section 3.1.2.2.9.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-053b	Stainless steel Westinghouse reactor internal Expansion components exposed to reactor coolant and neutron flux	Cracking due to SCC, irradiation-assisted SCC, fatigue	AMP XI.M16A, PWR Vessel Internals, and AMP XI.M2, Water Chemistry (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. See further evaluation in Section 3.1.2.2.9.
3.1.1-053c	Stainless steel, nickel alloy Westinghouse reactor internal Existing Programs components exposed to reactor coolant, neutron flux	Cracking due to SCC, irradiation-assisted SCC, fatigue	AMP XI.M16A, PWR Vessel Internals, and AMP XI.M2, Water Chemistry (for SCC mechanisms only)	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. See further evaluation in Section 3.1.2.2.9.
3.1.1-054	Stainless steel bottom mounted instrument system flux thimble tubes (with or without chrome plating) exposed to reactor coolant and neutron flux	Loss of material due to wear	AMP XI.M37, Flux Thimble Tube Inspection	No	Consistent with NUREG-2191.
3.1.1-055a	Stainless steel, nickel alloy Babcock and Wilcox 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 Code, 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)	Not applicable. NAPS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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 Code, 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)	Not applicable. NAPS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.
3.1.1-055c	Stainless steel, nickel alloy Westinghouse reactor internal No Additional Measures components exposed to reactor coolant, neutron flux	No additional aging management for reactor internal No Additional Measures components unless required by ASME Code, 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. See further evaluation in Section 3.1.2.2.9.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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)	Not applicable. NAPS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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)	Not applicable. NAPS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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)	Not applicable. NAPS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.
3.1.1-058a	Stainless steel (SS, including CASS, PH SS or martensitic SS), nickel alloy Babcock & Wilcox 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; or changes in dimensions due to void swelling or distortion; or loss of preload due to wear; or loss of material due to wear	AMP XI.M16A, PWR Vessel Internals	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. NAPS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-058b	Stainless steel (SS, including CASS, PH SS or martensitic SS), nickel alloy Babcock & Wilcox reactor internal Expansion components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement; or changes in dimensions due to void swelling, or distortion; or loss of preload due to thermal and irradiation-enhanced stress relaxation, or creep; or loss of material due to wear	AMP XI.M16A, PWR Vessel Internals	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. NAPS has Westinghouse reactor vessel internal components. The associated NUREG-2191 aging items are not used.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-059a	Stainless steel (SS, including CASS, PH SS or martensitic SS) or nickel alloy Westinghouse reactor internal Primary components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement; changes in dimensions due to void swelling, distortion; loss of preload due to thermal and irradiation-enhanced stress relaxation, creep; loss of material due to wear	AMP XI.M16A, PWR Vessel Internals	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. See further evaluation in Section 3.1.2.2.9.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-059b	Stainless steel (SS, including CASS, PH SS or martensitic SS) Westinghouse reactor internal Expansion components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement; changes in dimensions due to void swelling, distortion; loss of preload due to thermal and irradiation-enhanced stress relaxation, creep; loss of material due to wear	AMP XI.M16A, PWR Vessel Internals	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. See further evaluation in Section 3.1.2.2.9.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-059c	Stainless steel (SS, including CASS, PH SS or martensitic SS) or nickel alloy Westinghouse reactor internal Existing Programs components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement and for CASS, martensitic SS, and PH SS due to thermal aging embrittlement; changes in dimensions due to void swelling, distortion; loss of preload due to thermal and irradiation-enhanced stress relaxation, creep; loss of material due to wear	AMP XI.M16A, PWR Vessel Internals	Yes (SRP-SLR Section 3.1.2.2.9)	Consistent with NUREG-2191. See further evaluation in Section 3.1.2.2.9.
3.1.1-060	Steel piping, piping components exposed to reactor coolant	Wall thinning due to flow-accelerated corrosion	AMP XI.M17, Flow-Accelerated Corrosion	No	Not applicable - BWR only.
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.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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	Not applicable. NAPS high-strength steel closure bolting (closure head stud, nut, and washer) is addressed by row 3.1.1-092. The associated NUREG-2191 aging items are not used.
3.1.1-063	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	Not applicable - BWR only.
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.
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. NAPS has no in-scope stainless steel control rod drive head penetration flange bolting exposed to air-indoor uncontrolled in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
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	Not applicable. Steel, stainless steel closure bolting exposed to air-indoor uncontrolled is addressed by row 3.1.1-067. The associated NUREG-2191 aging items are not used.
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.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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. NAPS has no carbon steel tube support plates in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
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.
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.
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 with a different program for some component. The ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program is used instead of the Steam Generators (B2.1.10) program to manage cracking and loss of material for the feedwater nozzle thermal sleeve.
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.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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. NAPS has no in-scope nickel alloy steam generator tubes and sleeves exposed to phosphate chemistry in secondary feedwater or steam in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
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.
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. NAPS has no in-scope steel steam generator tube support lattice bars exposed to secondary feedwater or steam in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
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 with a different program for some component. The ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program is used instead of the Steam Generators (B2.1.10) program to manage loss of material for the feedwater nozzle thermal sleeve.
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, with a TLAA evaluation included. Wear of steam generator tubes at tube support plates is a TLAA, evaluated in Section 4.7.8, Steam Generator Tube Wear Evaluation.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-078	Nickel alloy steam generator components such as, secondary side nozzles (vent, drain, and instrumentation) exposed to secondary feedwater or steam	Cracking due to SCC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection, or AMP XI.M1, ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD.	No	Not applicable. NAPS has recirculating steam generators, not once-through. The associated NUREG-2191 aging items are not used.
3.1.1-079	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, and AMP XI.M32, One-Time Inspection	No	Not applicable - BWR only.
3.1.1-080	Stainless steel or steel with stainless steel cladding pressurizer relief tank: tank shell and heads, flanges, nozzles (none-ASME Code, 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. NAPS has no in-scope stainless steel or steel with stainless steel cladding pressurizer relief tank: tank shell and heads, flanges, nozzles (non-ASME Code, Section XI components) exposed to treated borated water >60°C (>140°F) in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope stainless steel pressurizer spray head exposed to reactor coolant in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope nickel alloy pressurizer spray head exposed to reactor coolant in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-083	Steel steam generator shell assembly exposed to secondary feedwater or steam	Loss of material due to general, pitting, crevice corrosion	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable. Loss of material of the steel steam generator shell assembly exposed to secondary feedwater or steam is addressed by item 3.1.1-012. The associated NUREG-2191 aging items are not used.
3.1.1-084	Steel top head enclosure (without cladding): top head, top head nozzles (vent, top head spray, RCIC, spare) exposed to reactor coolant	Loss of material due to general, pitting, crevice corrosion	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable - BWR only.
3.1.1-085	Stainless steel, nickel alloy, and steel with nickel alloy or stainless steel cladding reactor vessel flanges, nozzles, penetrations, safe ends, vessel shells, heads and welds exposed to reactor coolant	Loss of material due to pitting, crevice corrosion	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable - BWR only.
3.1.1-086	Stainless steel steam generator primary side divider plate exposed to reactor coolant	Cracking due to SCC	AMP XI.M2, Water Chemistry	No	Not applicable. NAPS has no in-scope stainless steel steam generator primary side divider plate exposed to reactor coolant in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.
3.1.1-087	Stainless steel, nickel alloy PWR reactor internal components exposed to reactor coolant, neutron flux	Loss of material due to pitting, crevice corrosion	AMP XI.M2, Water Chemistry	No	Not applicable. Loss of material for reactor vessel internal components exposed to reactor coolant and neutron flux is addressed by rows 3.1.1-028, 3.1.1-054, 3.1.1-059a, 3.1.1-059b, and 3.1.1-059c. The associated NUREG-2191 aging items are not used.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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. In addition to Reactor Vessel, Internals, and Reactor Coolant System, components in the Engineered Safety Features (residual heat removal and safety-injection) and Auxiliary Systems (chemical and volume control, and sampling) are aligned to this item.
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	Consistent with NUREG-2191.
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	Consistent with NUREG-2191.
3.1.1-091	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; loss of material due to general, pitting, crevice corrosion, wear	AMP XI.M3, Reactor Head Closure Stud Bolting	No	Not applicable - BWR only.
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 exceptions. Exceptions apply to the NUREG-2191 recommendations for Reactor Head Closure Stud Bolting (B2.1.3) program implementation.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191.
3.1.1-094	Stainless steel and nickel alloy vessel shell attachment welds exposed to reactor coolant	Cracking due to SCC, IGSCC, cyclic loading	AMP XI.M4, BWR Vessel ID Attachment Welds, and AMP XI.M2, Water Chemistry (SCC, IGSCC mechanisms only)	No	Not applicable - BWR only.
3.1.1-095	Steel (with or without stainless steel or nickel alloy cladding) feedwater nozzles exposed to reactor coolant	Cracking due to cyclic loading	AMP XI.M1, ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Not applicable - BWR only.
3.1.1-096	Steel (with or without stainless steel cladding) control rod drive return line nozzles and their nozzle-to-vessel welds exposed to reactor coolant in BWR-3, BWR-4, BWR-5, and BWR-6 designs	Cracking due to SCC, IGSCC, cyclic loading	AMP XI.M1, ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Not applicable - BWR only.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-097	Stainless steel and nickel alloy piping, piping components greater than or equal to 4 NPS; nozzle safe ends and associated welds; control rod drive return line nozzle cap and associated cap-to-nozzle weld or cap-to-safe end weld in BWR-3, BWR 4, BWR 5, and BWR-6 designs	Cracking due to SCC, IGSCC	AMP XI.M7, BWR Stress Corrosion Cracking, and AMP XI.M2, Water Chemistry	No	Not applicable - BWR only.
3.1.1-098	Stainless steel, nickel alloy penetrations: instrumentation and standby liquid control exposed to reactor coolant	Cracking due to SCC, IGSCC, cyclic loading	AMP XI.M8, BWR Penetrations, and AMP XI.M2, Water Chemistry (SCC, IGSCC mechanisms only)	No	Not applicable - BWR only.
3.1.1-099	Stainless steel (including cast austenitic stainless steel; PH martensitic stainless steel; martensitic stainless steel); nickel alloy (including X-750 alloy) reactor internal components exposed to reactor coolant and neutron flux	Loss of fracture toughness due to thermal aging, neutron irradiation embrittlement	AMP XI.M9, BWR Vessel Internals	Yes (SRP-SLR Section 3.1.2.2.13)	Not applicable - BWR only.
3.1.1-100	Stainless steel reactor vessel internals components (jet pump wedge surface) exposed to reactor coolant	Loss of material due to wear	AMP XI.M9, BWR Vessel Internals	No	Not applicable - BWR only.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-101	Stainless steel steam dryers exposed to reactor coolant	Cracking due to flow-induced vibration, SCC, IGSCC; loss of material due to wear	AMP XI.M9, BWR Vessel Internals	No	Not applicable - BWR only.
3.1.1-102	Stainless steel fuel supports and control rod drive assemblies control rod drive housing exposed to reactor coolant	Cracking due to SCC, IGSCC	AMP XI.M9, BWR Vessel Internals, and AMP XI.M2, Water Chemistry	No	Not applicable - BWR only.
3.1.1-103	Stainless steel, nickel alloy reactor internal components exposed to reactor coolant and neutron flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	AMP XI.M9, BWR Vessel Internals, and AMP XI.M2, Water Chemistry	Yes (SRP-SLR Section 3.1.2.2.12)	Not applicable - BWR only.
3.1.1-104	Nickel alloy reactor vessel internal components exposed to reactor coolant and neutron flux	Cracking due to IGSCC	AMP XI.M9, BWR Vessel Internals, and AMP XI.M2, Water Chemistry	No	Not applicable - BWR only.
3.1.1-105	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.1.2.2.15)	Consistent with NUREG-2191. See further evaluation 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 applicable. Boric acid corrosion is not an aging effect requiring management for nickel alloy. The associated NUREG-2191 aging items are not used.
3.1.1-107	Stainless steel piping, piping components exposed to gas, air with borated water leakage	None	None	No	Consistent with NUREG-2191.
3.1.1-110	Metallic piping, piping components exposed to reactor coolant	Wall thinning due to erosion	AMP XI.M17, Flow-Accelerated Corrosion	No	Not applicable - BWR only.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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.
3.1.1-113	Steel reactor vessel external attachments exposed to indoor, uncontrolled air	Loss of material due to general, pitting, crevice corrosion, wear	AMP XI.M1, ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Not applicable - BWR only.
3.1.1-114	Reactor coolant system components defined as ASME Code, Section XI Code Class components (ASME Code Class 1 reactor coolant pressure boundary components or core support structure components, or ASME Code Class 2 or 3 components - including ASME defined appurtenances, component supports, and associated pressure boundary welds, or components subject to plant-specific equivalent classifications for these ASME code classes)	Cracking due to SCC, IGSCC (stainless steel, nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	AMP XI.M1, ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and AMP XI.M2, Water Chemistry (water chemistry-related or corrosion-related aging effect mechanisms only)	No	Not applicable. Cracking and loss of material of reactor coolant system components defined as ASME Code, Section XI Code Class components (ASME Code Class 1 reactor coolant pressure boundary components or core support structure components, or ASME Code 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) is addressed by rows 3.1.1-020, 3.1.1-033, 3.1.1-035, 3.1.1-036, 3.1.1-037, 3.1.1-039, 3.1.1-042, 3.1.1-045, 3.1.1-088, and 3.1.1-116. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope stainless steel piping, piping components exposed to concrete in the Reactor Vessel, Internals, and Reactor Coolant System. The associated NUREG-2191 aging items are not used.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-116	Nickel alloy control rod drive penetration nozzles exposed to reactor coolant	Loss of material due to wear	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.10.1)	Consistent with NUREG-2191. Loss of material of nickel alloy control rod drive components exposed to reactor coolant is managed by the ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program. See further evaluation in Section 3.1.2.2.10.1.
3.1.1-117	Stainless steel, nickel alloy control rod drive penetration nozzle thermal sleeves exposed to reactor coolant	Loss of material due to wear	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.10.2)	Not applicable. Loss of material due to wear for stainless steel control rod drive penetration nozzle thermal sleeves exposed to reactor coolant is addressed by item 3.1.1-059a. The associated NUREG-2191 aging items are not used.
3.1.1-118	Stainless steel, nickel alloy PWR reactor vessel internal components exposed to reactor coolant, neutron flux	Cracking due to SCC, irradiation-assisted SCC, cyclic loading, fatigue	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. Cracking of stainless steel and nickel alloy PWR reactor vessel internal components exposed to reactor coolant and neutron flux is addressed by items 3.1.1-053a, 3.1.1-053b and 3.1.1-053c. The associated NUREG-2191 aging items are not used.
3.1.1-119	Stainless steel, nickel alloy PWR reactor vessel internal components exposed to reactor coolant, neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement or thermal aging embrittlement; changes in dimensions due to void swelling or distortion; loss of preload due to thermal and irradiation-enhanced stress relaxation or creep; loss of material due to wear	Plant-specific aging management program	Yes (SRP-SLR Section 3.1.2.2.9)	Not applicable. Loss of fracture toughness, changes in dimensions, loss of preload, and loss of material of stainless steel and nickel alloy PWR reactor vessel internal components exposed to reactor coolant and neutron flux are addressed by items 3.1.1-059a, 3.1.1-059b and 3.1.1-059c. The associated NUREG-2191 aging items are not used.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-120	Stainless steel core plate rim holddown bolts exposed to reactor coolant and neutron flux	Loss of preload due to thermal or irradiation-enhanced stress relaxation	AMP XI.M9, BWR Vessel Internals, and TLAA SRP-SLR 4.7 Other Plant-Specific TLAAs [if an analysis is performed as part of the aging management basis and conforms to the definition of a TLAA in 10 CFR 54.3(a)]	Yes (SRP-SLR Section 3.1.2.2.14)	Not applicable - BWR only.
3.1.1-121	Stainless steel jet pump assembly holddown beam bolts exposed to reactor coolant and neutron flux	Loss of preload due to thermal or irradiation-enhanced stress relaxation	AMP XI.M9, BWR Vessel Internals	No	Not applicable - BWR only.
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.
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.
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 and a different aging management program is credited for some components. The ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program will manage loss of material of the steel with stainless steel cladding steam generator primary inlet and outlet nozzles, and the stainless steel primary inlet and outlet nozzle safe ends, exposed to reactor coolant, instead of the Water Chemistry (B2.1.2) and Steam Generators (B2.1.10) programs.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-128	Stainless steel, nickel alloy nozzles safe ends and welds: high pressure core spray; low pressure core spray; recirculating water, low pressure coolant injection or RHR injection mode exposed to reactor coolant	Cracking due to SCC, IGSCC	AMP XI.M7, BWR Stress Corrosion Cracking, and AMP XI.M2, Water Chemistry	No	Not applicable - BWR only.
3.1.1-129	Steel and stainless steel piping, piping components exposed to reactor coolant: welded connections between the re-routed control rod drive return line and the inlet piping system that delivers return line flow to the reactor pressure vessel exposed to reactor coolant	Cracking due to cyclic loading	AMP XI.M1, ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	No	Not applicable - BWR only.
3.1.1-133	Steel components exposed to treated water	Long-term loss of material due to general corrosion	AMP XI.M32, One-Time Inspection	No	Not applicable - BWR only.
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	Consistent with NUREG-2191.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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. Loss of material of the nickel alloy reactor vessel flange leakage monitor tube and the stainless steel reactor vessel flange leakage detection line piping exposed to air-indoor uncontrolled is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program. Loss of material of other stainless steel and nickel alloy piping, piping components exposed to air-indoor uncontrolled is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.1.2.2.16.
3.1.1-137	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191.
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)	Consistent with NUREG-2191. Cracking of the nickel alloy reactor vessel leakage monitor tube and the stainless steel reactor vessel flange leakage detection line piping exposed to air-indoor uncontrolled is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program. See further evaluation in Section 3.1.2.2.6.3.

Results Tables: Reactor Vessel, Internals, and Reactor Coolant System AMR Results

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bottom head dome	PB	Steel with stainless steel cladding	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.A2.RP-379	3.1.1-048	A
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.A2.RP-379	3.1.1-048	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-234	3.1.1-046	C
					Water Chemistry (B2.1.2)	IV.A2.RP-234	3.1.1-046	C
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Bottom mounted instrumentation guide tube	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-154	3.1.1-019	E, 2
					Water Chemistry (B2.1.2)	IV.A2.RP-154	3.1.1-019	E, 2
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Bottom mounted instrumentation nozzle and weld	PB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-59	3.1.1-045	A
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.A2.RP-59	3.1.1-045	A
					Water Chemistry (B2.1.2)	IV.A2.RP-59	3.1.1-045	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Closure head dome	PB	Steel with stainless steel cladding	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.A2.RP-379	3.1.1-048	A
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.A2.RP-379	3.1.1-048	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-234	3.1.1-046	A
					Water Chemistry (B2.1.2)	IV.A2.RP-234	3.1.1-046	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Closure head flange	PB	Steel with stainless steel cladding	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.A2.RP-379	3.1.1-048	A
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.A2.RP-379	3.1.1-048	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-234	3.1.1-046	A
					Water Chemistry (B2.1.2)	IV.A2.RP-234	3.1.1-046	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Closure head lifting lug	SS	Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.A2.R-17	3.1.1-049	A
Closure head stud, nut, and washer	PB	High-strength steel	(E) Air – indoor uncontrolled	Cracking	Reactor Head Closure Stud Bolting (B2.1.3)	IV.A2.RP-52	3.1.1-092	B
				Cumulative fatigue damage	TLAA	IV.A2.RP-54	3.1.1-001	A
				Loss of material	Reactor Head Closure Stud Bolting (B2.1.3)	IV.A2.RP-53	3.1.1-092	B
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.A2.R-17	3.1.1-049	A

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Control rod drive mechanism (head adapter plug)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-55	3.1.1-047	A
					Water Chemistry (B2.1.2)	IV.A2.RP-55	3.1.1-047	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Control rod drive mechanism (housing (head adapter) flange)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-55	3.1.1-047	A
					Water Chemistry (B2.1.2)	IV.A2.RP-55	3.1.1-047	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Control rod drive mechanism (housing (head adapter) tube)	PB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-186	3.1.1-045	A
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.A2.RP-186	3.1.1-045	A
					Water Chemistry (B2.1.2)	IV.A2.RP-186	3.1.1-045	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.R-413	3.1.1-116	E, 1

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Control rod drive mechanism (latch housing)	PB	Cast austenitic stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C
			(I) Reactor coolant >250°C (>482°F)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-55	3.1.1-047	A
					Water Chemistry (B2.1.2)	IV.A2.RP-55	3.1.1-047	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of fracture toughness	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B2.1.6)	IV.A2.R-77	3.1.1-050	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Control rod drive mechanism (nozzle, head vent nozzle, j-groove weld)	PB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-186	3.1.1-045	A
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.A2.RP-186	3.1.1-045	A
					Water Chemistry (B2.1.2)	IV.A2.RP-186	3.1.1-045	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Control rod drive mechanism (rod travel housing)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-55	3.1.1-047	A
					Water Chemistry (B2.1.2)	IV.A2.RP-55	3.1.1-047	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Core support lug, pad and weld	SS	Nickel alloy	(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-57	3.1.1-040a	A, 3
					Water Chemistry (B2.1.2)	IV.A2.RP-57	3.1.1-040a	A, 3
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A, 3
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A, 3
Instrumentation port assembly	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-55	3.1.1-047	C
					Water Chemistry (B2.1.2)	IV.A2.RP-55	3.1.1-047	C
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Instrumentation tube	PB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-59	3.1.1-045	A
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.A2.RP-59	3.1.1-045	A
					Water Chemistry (B2.1.2)	IV.A2.RP-59	3.1.1-045	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Instrumentation tube safe end	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-55	3.1.1-047	C
					Water Chemistry (B2.1.2)	IV.A2.RP-55	3.1.1-047	C
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Primary nozzle and support pad	PB;SS	Steel with stainless steel cladding	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.A2.R-17	3.1.1-049	A
			(I) Reactor coolant and neutron flux	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-234	3.1.1-046	A
					Water Chemistry (B2.1.2)	IV.A2.RP-234	3.1.1-046	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of fracture toughness	TLAA	IV.A2.R-84	3.1.1-013	A
					Neutron Fluence Monitoring (B3.2)	IV.A2.RP-229	3.1.1-014	A
					Reactor Vessel Material Surveillance (B2.1.19)	IV.A2.RP-229	3.1.1-014	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Primary nozzle safe end	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-234	3.1.1-046	A
					Water Chemistry (B2.1.2)	IV.A2.RP-234	3.1.1-046	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Refueling seal ledge	SS	Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.A2.R-17	3.1.1-049	A
Seal table	SS	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C
Seal table fitting	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-217	3.1.1-033	C
					Water Chemistry (B2.1.2)	IV.C2.R-217	3.1.1-033	C
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Vent pipe nozzle	PB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.R-90	3.1.1-045	A
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.A2.R-90	3.1.1-045	A
					Water Chemistry (B2.1.2)	IV.A2.R-90	3.1.1-045	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Ventilation shroud support ring	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.A2.R-17	3.1.1-049	A
Vessel flange and core support ledge	PB;SS	Steel with stainless steel cladding	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.A2.R-17	3.1.1-049	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-234	3.1.1-046	A
					Water Chemistry (B2.1.2)	IV.A2.RP-234	3.1.1-046	A
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.R-87	3.1.1-037	A
					Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Vessel flange leakage monitor tube	PB	Nickel alloy	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.A2.R-74b	3.1.1-139	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.R-90	3.1.1-045	C
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.A2.R-90	3.1.1-045	C
					Water Chemistry (B2.1.2)	IV.A2.R-90	3.1.1-045	C
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A
Vessel shell (upper, intermediate, and lower)	PB	Steel with stainless steel cladding	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.A2.R-17	3.1.1-049	A
			(I) Reactor coolant and neutron flux	Crack growth	TLAA	IV.A2.R-85	3.1.1-018	A
				Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-234	3.1.1-046	C
					Water Chemistry (B2.1.2)	IV.A2.RP-234	3.1.1-046	C
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of fracture toughness	TLAA	IV.A2.R-84	3.1.1-013	A
					Neutron Fluence Monitoring (B3.2)	IV.A2.RP-229	3.1.1-014	A
					Reactor Vessel Material Surveillance (B2.1.19)	IV.A2.RP-229	3.1.1-014	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	A

Table 3.1.2-1 Plant-Specific Notes:

1. The plant-specific aging management program used to manage loss of material due to wear for the control rod drive mechanism housing (head adapter) tube is the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program.
2. The plant-specific aging management programs used to manage cracking of stainless steel bottom mounted instrumentation guide tubes are the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program and the Water Chemistry (B2.1.2) program.
3. The core support lug is an integral part of the reactor vessel and is also known as the clevis. The associated clevis insert bolting is addressed in the reactor vessel internals aging management review.

Table 3.1.2-2 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel Internals - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Alignment and interfacing (clevis bearing wear surface)	SS	Stellite™	(E) Reactor coolant and neutron flux	Loss of material	PWR Vessel Internals (B2.1.7)	None	None	F, 5
Alignment and interfacing (clevis insert bolt and dowel)	SS	Nickel alloy	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-399	3.1.1-053c	A
					Water Chemistry (B2.1.2)	IV.B2.RP-399	3.1.1-053c	A
				Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-356	3.1.1-028	C
Alignment and interfacing (internals hold down spring)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Loss of preload; changes in dimensions; loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-300	3.1.1-059a	A, 3
Alignment and interfacing (thermal sleeve)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-302a	3.1.1-059a	C
Alignment and interfacing (upper core plate alignment pin)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-299	3.1.1-059c	A
Baffle former (baffle edge bolt)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-275	3.1.1-053a	A
					Water Chemistry (B2.1.2)	IV.B2.RP-275	3.1.1-053a	A
				Loss of fracture toughness; changes in dimensions; loss of preload	PWR Vessel Internals (B2.1.7)	IV.B2.RP-354	3.1.1-059a	A
				Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-296	3.1.1-059a	C
Baffle former (baffle former bolt)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-271	3.1.1-053a	A
					Water Chemistry (B2.1.2)	IV.B2.RP-271	3.1.1-053a	A
				Loss of fracture toughness; changes in dimensions; loss of preload	PWR Vessel Internals (B2.1.7)	IV.B2.RP-354	3.1.1-059a	A, 4
				Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-296	3.1.1-059a	C

Table 3.1.2-2 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel Internals - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Baffle former (baffle plate)	FD;SS	Stainless steel	(E) Reactor coolant and neutron flux	Changes in dimensions	PWR Vessel Internals (B2.1.7)	IV.B2.RP-270	3.1.1-059a	A
				Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-270a	3.1.1-053a	A
					Water Chemistry (B2.1.2)	IV.B2.RP-270a	3.1.1-053a	A
				Loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-388	3.1.1-059a	A
Baffle former (former plate)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Changes in dimensions	PWR Vessel Internals (B2.1.7)	IV.B2.RP-270	3.1.1-059a	A
				Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-270a	3.1.1-053a	A
					Water Chemistry (B2.1.2)	IV.B2.RP-270a	3.1.1-053a	A
Bottom mounted instrumentation (column body)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-293	3.1.1-053b	A
				Loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-295	3.1.1-059b	A
Bottom-mounted instrumentation (flux thimble tube)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Loss of material	Flux Thimble Tube Inspection (B2.1.24)	IV.B2.RP-284	3.1.1-054	A
Control rod guide tube (continuous section sheath and C-tube)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-290b	3.1.1-059b	C
Control rod guide tube (guide plate - Unit 2 only)	SS	Cast austenitic stainless steel	(E) Reactor coolant >250°C (>482°F) and neutron flux	Loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-297	3.1.1-059a	C
				Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-296	3.1.1-059a	A
Control rod guide tube (guide plate)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-296	3.1.1-059a	A
Control rod guide tube (lower flange - Unit 2 only)	SS	Cast austenitic stainless steel	(E) Reactor coolant >250°C (>482°F) and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-298	3.1.1-053a	C
					Water Chemistry (B2.1.2)	IV.B2.RP-298	3.1.1-053a	C
				Loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-297	3.1.1-059a	C
Control rod guide tube (lower flange)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-298	3.1.1-053a	C
					Water Chemistry (B2.1.2)	IV.B2.RP-298	3.1.1-053a	C
				Loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-297	3.1.1-059a	C

Table 3.1.2-2 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel Internals - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Core barrel (barrel former bolt)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-273	3.1.1-053b	A
					Water Chemistry (B2.1.2)	IV.B2.RP-273	3.1.1-053b	A
				Loss of fracture toughness; changes in dimensions; loss of preload	PWR Vessel Internals (B2.1.7)	IV.B2.RP-274	3.1.1-059b	A
Core barrel (core barrel flange)	FD;SS	Stainless steel	(E) Reactor coolant and neutron flux	Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-345	3.1.1-059c	A
Core barrel (lower axial weld)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-387a	3.1.1-053b	A
					Water Chemistry (B2.1.2)	IV.B2.RP-387a	3.1.1-053b	A
				Loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-388a	3.1.1-059b	A
Core barrel (lower flange weld)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-280	3.1.1-053a	A
					Water Chemistry (B2.1.2)	IV.B2.RP-280	3.1.1-053a	A
Core barrel (lower girth weld)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-387	3.1.1-053a	A
					Water Chemistry (B2.1.2)	IV.B2.RP-387	3.1.1-053a	A
				Loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-388	3.1.1-059a	A
Core barrel (middle axial weld)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-387a	3.1.1-053b	A
					Water Chemistry (B2.1.2)	IV.B2.RP-387a	3.1.1-053b	A
				Loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-388a	3.1.1-059b	A
Core barrel (upper axial weld)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-387a	3.1.1-053b	A
					Water Chemistry (B2.1.2)	IV.B2.RP-387a	3.1.1-053b	A
Core barrel (upper flange weld)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-276	3.1.1-053a	A
					Water Chemistry (B2.1.2)	IV.B2.RP-276	3.1.1-053a	A
Core barrel (upper girth weld)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-387	3.1.1-053a	A
					Water Chemistry (B2.1.2)	IV.B2.RP-387	3.1.1-053a	A
Lower internals (fuel alignment pin)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-299	3.1.1-059c	C

Table 3.1.2-2 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel Internals - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Lower internals (lower core plate)	FD;SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-289	3.1.1-053c	A
					Water Chemistry (B2.1.2)	IV.B2.RP-289	3.1.1-053c	A
				Cumulative fatigue damage	TLAA	IV.B2.RP-303	3.1.1-003	A, 2
				Loss of fracture toughness; loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-288	3.1.1-059c	A
Lower internals (radial support key wear surface)	SS	Stellite™	(E) Reactor coolant and neutron flux	Loss of material	PWR Vessel Internals (B2.1.7)	None	None	F, 5
Lower support (column body)	SS	Cast austenitic stainless steel	(E) Reactor coolant >250°C (>482°F) and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-291	3.1.1-053b	A
					Water Chemistry (B2.1.2)	IV.B2.RP-291	3.1.1-053b	A
				Loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-290	3.1.1-059b	A
Lower support (column bolt)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-286	3.1.1-053b	A
					Water Chemistry (B2.1.2)	IV.B2.RP-286	3.1.1-053b	A
				Loss of fracture toughness; loss of preload	PWR Vessel Internals (B2.1.7)	IV.B2.RP-287	3.1.1-059b	A
Lower support (lower support forging)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-291a	3.1.1-053b	A
No additional measures components	FD;SP;SS	Cast austenitic stainless steel	(E) Reactor coolant >250°C (>482°F) and neutron flux	None	PWR Vessel Internals (B2.1.7)	IV.B2.RP-265	3.1.1-055c	A, 1
		Nickel alloy	(E) Reactor coolant and neutron flux	None	PWR Vessel Internals (B2.1.7)	IV.B2.RP-265	3.1.1-055c	A, 1
		Stainless steel	(E) Reactor coolant and neutron flux	None	PWR Vessel Internals (B2.1.7)	IV.B2.RP-265	3.1.1-055c	A, 1
		Stellite™	(E) Reactor coolant and neutron flux	None	PWR Vessel Internals (B2.1.7)	None	None	F, 1
Thermal shield (flexure)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-302	3.1.1-053a	A
					Water Chemistry (B2.1.2)	IV.B2.RP-302	3.1.1-053a	A
				Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-302a	3.1.1-059a	A

Table 3.1.2-2 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel Internals - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Upper internals (fuel alignment pin)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Loss of material	PWR Vessel Internals (B2.1.7)	IV.B2.RP-299	3.1.1-059c	C
Upper internals (upper core plate)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-291b	3.1.1-053b	A
					Water Chemistry (B2.1.2)	IV.B2.RP-291b	3.1.1-053b	A
				Cumulative fatigue damage	TLAA	IV.B2.RP-303	3.1.1-003	A ,2
				Loss of fracture toughness	PWR Vessel Internals (B2.1.7)	IV.B2.RP-295	3.1.1-059b	C
Upper internals (upper support ring)	SS	Stainless steel	(E) Reactor coolant and neutron flux	Cracking	PWR Vessel Internals (B2.1.7)	IV.B2.RP-346	3.1.1-053c	A
					Water Chemistry (B2.1.2)	IV.B2.RP-346	3.1.1-053c	A

Table 3.1.2-2 Plant-Specific Notes:

1. No additional measures components are itemized in the MRP-227-A Gap Analysis.
2. Fatigue analyses were performed for the upper and lower core plates, as described in Section 4.3, Metal Fatigue.
3. Changes in dimensions and loss of material are not applicable aging effects for the internals hold down spring.
4. Changes in dimensions is not an applicable aging effect for the baffle former bolt.
5. The clevis bearing wear surface and the radial support key wear surface are fabricated of Stellite™. Loss of material due to wear is identified in the MRP-227-A Gap Analysis for these components, and is managed by the PWR Vessel Internals (B2.1.7) program.

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Cumulative fatigue damage	TLAA	IV.C2.RP-44	3.1.1-011	A
				Loss of material	Bolting Integrity (B2.1.9)	IV.C2.RP-166	3.1.1-064	A
				Loss of preload	Bolting Integrity (B2.1.9)	IV.D1.RP-46	3.1.1-067	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.RP-167	3.1.1-049	A
Drip pan (reactor coolant pump oil collection)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Enclosure (reactor coolant pump oil collection)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Flame arrestor	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
Flexible hose	PB	Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Heat exchanger (reactor coolant pump motor lower bearing oil - tube)	PB	Copper alloy	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	IV.C2.RP-222	3.1.1-090	C, 2
			(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	V.A.EP-76	3.2.1-050	C, 2
					One-Time Inspection (B2.1.20)	V.A.EP-76	3.2.1-050	C, 2

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (reactor coolant pump motor stator - fin)	HT	Copper alloy	(E) Air – indoor uncontrolled	Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-424	3.2.1-081	A
Heat exchanger (reactor coolant pump motor stator - tube)	HT;PB	Copper alloy	(E) Air – indoor uncontrolled	Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-424	3.2.1-081	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	IV.C2.RP-222	3.1.1-090	C, 2
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	V.A.EP-100	3.2.1-033	A, 2
Heat exchanger (reactor coolant pump motor upper bearing oil - channel head)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	C
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	IV.C2.RP-221	3.1.1-089	C
Heat exchanger (reactor coolant pump motor upper bearing oil - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	C
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	V.A.E-473	3.2.1-130	A
					One-Time Inspection (B2.1.20)	V.A.E-473	3.2.1-130	A
Heat exchanger (reactor coolant pump motor upper bearing oil - tube)	PB	Copper alloy (>15% Zn)	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	IV.C2.RP-222	3.1.1-090	C
					Selective Leaching (B2.1.21)	IV.C2.RP-12	3.1.1-093	C
			(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	V.A.EP-76	3.2.1-050	C
					One-Time Inspection (B2.1.20)	V.A.EP-76	3.2.1-050	C
Heat exchanger (reactor coolant pump motor upper bearing oil - tubesheet)	PB	Steel	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	IV.C2.RP-221	3.1.1-089	C
			(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	V.A.E-473	3.2.1-130	A
					One-Time Inspection (B2.1.20)	V.A.E-473	3.2.1-130	A

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (thermal barrier)	HT;PB	Stainless steel	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	V.A.EP-93	3.2.1-031	A, 2
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	V.A.EP-96	3.2.1-033	A, 2
			(E) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	C, 2
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	C, 2
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A, 2
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A, 2
Hydraulic isolator	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
Insulation (RTD)	TI	Fiberglass	(E) Air – indoor uncontrolled	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-450	3.1.1-134	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C
Orifice	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping (reactor vessel flange leakage detection line)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.A2.R-74b	3.1.1-139	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-55	3.1.1-047	C
					Water Chemistry (B2.1.2)	IV.A2.RP-55	3.1.1-047	C
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	C
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	C
Piping, piping components	LB;PB	Copper alloy	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	None	None	IV.E.R-453	3.1.1-137	A
		Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-159	3.1.1-045	A
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.C2.RP-159	3.1.1-045	A
					Water Chemistry (B2.1.2)	IV.C2.RP-159	3.1.1-045	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Gas	None	None	IV.E.RP-07	3.1.1-107	A
			(I) Reactor coolant	Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Stainless steel	(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.A.E-12	3.2.1-020	A
					Water Chemistry (B2.1.2)	V.A.E-12	3.2.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A, 4
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	A
			(I) Gas	None	None	V.F.EP-7	3.2.1-064	A
Piping, piping components (Class 1)	PB	Cast austenitic stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant >250°C (>482°F)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-05	3.1.1-020	E, 1
					Water Chemistry (B2.1.2)	IV.C2.R-05	3.1.1-020	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-56	3.1.1-035	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of fracture toughness	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B2.1.6)	IV.C2.R-52	3.1.1-050	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components (Class 1)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-56	3.1.1-035	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Piping, piping components (Class 1<NPS 4)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	A
					ASME Code Class 1 Small-Bore Piping (B2.1.22)	IV.C2.RP-235	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-235	3.1.1-039	A
					Water Chemistry (B2.1.2)	IV.C2.RP-235	3.1.1-039	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Pressurizer (heater well and sheath)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-217	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.R-217	3.1.1-033	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pressurizer (instrument nozzle)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Pressurizer (lower head)	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Pressurizer (manway cover bolting)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	IV.C2.RP-166	3.1.1-064	A
				Loss of preload	Bolting Integrity (B2.1.9)	IV.D1.RP-46	3.1.1-067	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.RP-167	3.1.1-049	A
Pressurizer (manway cover)	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pressurizer (manway)	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Pressurizer (relief nozzle safe end)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Pressurizer (relief nozzle)	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pressurizer (relief, safety, spray, and surge nozzle welds)	PB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-156	3.1.1-045	A
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.C2.RP-156	3.1.1-045	A
					Water Chemistry (B2.1.2)	IV.C2.RP-156	3.1.1-045	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Pressurizer (safety nozzle safe end)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Pressurizer (safety nozzle)	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pressurizer (sample nozzle)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Pressurizer (shell)	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Pressurizer (seismic support lug)	SS	Steel	(E) Air – indoor uncontrolled	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-19	3.1.1-036	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	C
Pressurizer (spray nozzle safe end)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pressurizer (spray nozzle thermal sleeve)	LTC	Stainless steel	(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Pressurizer (spray nozzle)	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Pressurizer (support skirt and flange)	SS	Steel	(E) Air – indoor uncontrolled	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-19	3.1.1-036	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	C
Pressurizer (surge nozzle safe end)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Pressurizer (surge nozzle thermal sleeve)	LTC	Stainless steel	(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pressurizer (surge nozzle)	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Pressurizer (upper head)	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-58	3.1.1-040	A
						IV.C2.R-25	3.1.1-042	A
					Water Chemistry (B2.1.2)	IV.C2.R-25	3.1.1-042	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Pump casing (reactor coolant)	PB	Cast austenitic stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant >250°C (>482°F)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-09	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.R-09	3.1.1-033	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of fracture toughness	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B2.1.6)	IV.C2.R-52	3.1.1-050	A
					TLAA	IV.C2.R-52	3.1.1-050	E, 3
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Rupture disc	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Gas	None	None	IV.E.RP-07	3.1.1-107	A

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Sight glass	PB	Glass	(E) Air – indoor uncontrolled	None	None	V.F.EP-15	3.2.1-060	A
			(I) Waste water	None	None	VII.J.AP-277	3.3.1-119	A
Sight glass (body)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Tank (calibration test pots)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
Tank (neutron shield)	PB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A
					External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	IV.C2.RP-221	3.1.1-089	A
			(E) Concrete	None	None	IV.E.RP-353	3.1.1-105	A
Tank (pressurizer relief)	PB	Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	A
			(I) Treated water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	V.C.E-401	3.2.1-072	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	V.C.E-414	3.2.1-073	B

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (reactor coolant pump oil collection)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Valve body	LB;PB	Copper alloy (>15% Zn)	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-406	3.2.1-071	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.EP-38	3.2.1-008	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Gas	None	None	IV.E.RP-07	3.1.1-107	A
			(I) Reactor coolant	Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A, 4
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.C2.R-17	3.1.1-049	A
			(I) Gas	None	None	V.F.EP-7	3.2.1-064	A

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body (Class 1)	PB	Cast austenitic stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant >250°C (>482°F)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-09	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.R-09	3.1.1-033	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of fracture toughness	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-08	3.1.1-038	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.1.2-3 Plant-Specific Notes:

1. The plant-specific aging management program used to manage cracking of ASME class 1 cast austenitic stainless steel piping is the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program.
2. Coolers do not have a shell side or a tubesheet. The reactor coolant pump lower bearing oil cooler is a coiled tube design.
3. Fatigue crack growth of the reactor coolant pump casing is a plant-specific TLAA evaluated in Section 4.7.6, Reactor Coolant Pump Code Case N-481.
4. Flow blockage is addressed by the cited NUREG-2192 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Anti-vibration bar	SS	Stainless steel	(E) Treated water >60°C (>140°F)	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-384	3.1.1-071	A
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	A
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-226	3.1.1-071	A
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	A
					Steam Generators (B2.1.10)	IV.D1.RP-225	3.1.1-076	A
Channel head	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Reactor coolant	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-232	3.1.1-033	E, 2
					Water Chemistry (B2.1.2)	IV.D1.RP-232	3.1.1-033	C
				Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	A
				Loss of material	Steam Generators (B2.1.10)	IV.D1.R-436	3.1.1-127	A
					Water Chemistry (B2.1.2)	IV.D1.R-436	3.1.1-127	A
Channel head divider plate	FD	Nickel alloy	(E) Reactor coolant	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-367	3.1.1-025	A
					Water Chemistry (B2.1.2)	IV.D1.RP-367	3.1.1-025	A
				Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	C
Feedwater distribution ring and J-nozzles	FD	Steel	(E) Treated water	Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-161	3.1.1-072	C
					Water Chemistry (B2.1.2)	IV.D1.RP-161	3.1.1-072	C
					Steam Generators (B2.1.10)	IV.D1.RP-225	3.1.1-076	C
			(I) Treated water	Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-161	3.1.1-072	C
					Water Chemistry (B2.1.2)	IV.D1.RP-161	3.1.1-072	C
					Steam Generators (B2.1.10)	IV.D1.RP-225	3.1.1-076	C
				Wall thinning	Steam Generators (B2.1.10)	IV.D1.RP-49	3.1.1-074	A
					Water Chemistry (B2.1.2)	IV.D1.RP-49	3.1.1-074	A

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Feedwater nozzle	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Treated water	Cumulative fatigue damage	TLAA	IV.D1.R-33	3.1.1-005	A
				Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-368	3.1.1-012	C
					Water Chemistry (B2.1.2)	IV.D1.RP-368	3.1.1-012	C
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	IV.D1.R-37	3.1.1-061	A
Feedwater nozzle thermal sleeve	LTC	Stainless steel	(I) Treated water >60°C (>140°F)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-384	3.1.1-071	E, 5
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	C
				Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-226	3.1.1-071	E, 5
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	C
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-225	3.1.1-076	E, 5
Moisture separator assembly	FD	Steel	(E) Treated water	Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-161	3.1.1-072	C
					Water Chemistry (B2.1.2)	IV.D1.RP-161	3.1.1-072	C
				Wall thinning	Steam Generators (B2.1.10)	IV.D1.RP-49	3.1.1-074	A
					Water Chemistry (B2.1.2)	IV.D1.RP-49	3.1.1-074	A
			(I) Treated water	Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-161	3.1.1-072	C
					Water Chemistry (B2.1.2)	IV.D1.RP-161	3.1.1-072	C
				Wall thinning	Steam Generators (B2.1.10)	IV.D1.RP-49	3.1.1-074	A
					Water Chemistry (B2.1.2)	IV.D1.RP-49	3.1.1-074	A

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Primary inlet and outlet nozzle	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-232	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.D1.RP-232	3.1.1-033	A
				Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	A
				Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.R-436	3.1.1-127	E, 1
					Water Chemistry (B2.1.2)	IV.D1.R-436	3.1.1-127	A
Primary inlet and outlet nozzle safe end	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-232	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.D1.RP-232	3.1.1-033	A
				Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	A
				Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.R-436	3.1.1-127	E, 1
					Water Chemistry (B2.1.2)	IV.D1.R-436	3.1.1-127	A
Primary inlet and outlet nozzle weld	PB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	IV.C2.R-452a	3.1.1-136	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-159	3.1.1-045	C
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.C2.RP-159	3.1.1-045	C
					Water Chemistry (B2.1.2)	IV.C2.RP-159	3.1.1-045	C
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Primary manway	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-232	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.D1.RP-232	3.1.1-033	A
				Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	A
				Loss of material	Steam Generators (B2.1.10)	IV.D1.R-436	3.1.1-127	A
					Water Chemistry (B2.1.2)	IV.D1.R-436	3.1.1-127	A
Primary manway cover	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
Primary manway cover bolting	PB	Steel	(E) Air – indoor uncontrolled	Cumulative fatigue damage	TLAA	IV.C2.R-18	3.1.1-005	A
				Loss of material	Bolting Integrity (B2.1.9)	IV.D1.RP-166	3.1.1-064	A
				Loss of preload	Bolting Integrity (B2.1.9)	IV.D1.RP-46	3.1.1-067	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
Primary manway cover insert	PB	Nickel alloy	(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-159	3.1.1-045	C
					Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (B2.1.5)	IV.C2.RP-159	3.1.1-045	C
					Water Chemistry (B2.1.2)	IV.C2.RP-159	3.1.1-045	C
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Secondary closure cover	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Treated water	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-368	3.1.1-012	C
					Water Chemistry (B2.1.2)	IV.D1.RP-368	3.1.1-012	C
Secondary closure cover bolting	PB	Steel	(E) Air – indoor uncontrolled	Cumulative fatigue damage	TLAA	IV.C2.R-18	3.1.1-005	A
				Loss of material	Bolting Integrity (B2.1.9)	IV.D1.RP-166	3.1.1-064	A
				Loss of preload	Bolting Integrity (B2.1.9)	IV.D1.RP-46	3.1.1-067	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
Secondary manway (includes pad)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Steam	Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-368	3.1.1-012	A
					Water Chemistry (B2.1.2)	IV.D1.RP-368	3.1.1-012	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.R-31	3.1.1-044	A
Secondary side shell (lower shell, upper shell, transition cone, closure weld, girth weld)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Treated water	Cumulative fatigue damage	TLAA	IV.D1.R-33	3.1.1-005	A
				Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-368	3.1.1-012	A
					One-Time Inspection (B2.1.20)	IV.D1.RP-368	3.1.1-012	E, 4
					Water Chemistry (B2.1.2)	IV.D1.RP-368	3.1.1-012	A

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Secondary side shell (penetrations)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Treated water	Cumulative fatigue damage	TLAA	IV.D1.R-33	3.1.1-005	A
				Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-368	3.1.1-012	A
					Water Chemistry (B2.1.2)	IV.D1.RP-368	3.1.1-012	A
Secondary side shell (upper head)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Steam	Cumulative fatigue damage	TLAA	IV.D1.R-33	3.1.1-005	A
				Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-368	3.1.1-012	A
					Water Chemistry (B2.1.2)	IV.D1.RP-368	3.1.1-012	A
Stay rod and spacer	SS	Steel	(E) Treated water	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-384	3.1.1-071	A
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	A
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-226	3.1.1-071	A
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	A
					Steam Generators (B2.1.10)	IV.D1.RP-225	3.1.1-076	A
Steam flow limiter	RF	Nickel alloy	(E) Steam	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-384	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	C
				Cumulative fatigue damage	TLAA	IV.D1.R-46	3.1.1-002	C
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-226	3.1.1-071	C
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	C

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Steam outlet nozzle	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
			(I) Steam	Cumulative fatigue damage	TLAA	IV.D1.R-33	3.1.1-005	A
				Loss of material	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.D1.RP-368	3.1.1-012	A
					Water Chemistry (B2.1.2)	IV.D1.RP-368	3.1.1-012	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	IV.D1.R-37	3.1.1-061	A
Support pad	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-431	3.1.1-124	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	IV.D1.R-17	3.1.1-049	A
Tube	HT;PB	Nickel alloy	(I) Reactor coolant	Cracking	Steam Generators (B2.1.10)	IV.D1.R-44	3.1.1-070	A
					Water Chemistry (B2.1.2)	IV.D1.R-44	3.1.1-070	A
				Cumulative fatigue damage	TLAA	IV.D1.R-46	3.1.1-002	A
			(E) Treated water >60°C (>140°F)	Cracking	Steam Generators (B2.1.10)	IV.D1.R-47	3.1.1-069	A
					Water Chemistry (B2.1.2)	IV.D1.R-47	3.1.1-069	A
					Steam Generators (B2.1.10)	IV.D1.R-437	3.1.1-125	A
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-233	3.1.1-077	A
					TLAA	IV.D1.RP-233	3.1.1-077	E, 3
				Reduction of heat transfer	Steam Generators (B2.1.10)	IV.D1.R-407	3.1.1-111	A
					Water Chemistry (B2.1.2)	IV.D1.R-407	3.1.1-111	A
Tube bundle wrapper	FD;SS	Steel	(E) Treated water	Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-161	3.1.1-072	A
					Water Chemistry (B2.1.2)	IV.D1.RP-161	3.1.1-072	A
Tube plug	PB	Nickel alloy	(E) Reactor coolant	Cracking	Steam Generators (B2.1.10)	IV.D1.R-40	3.1.1-070	A
					Water Chemistry (B2.1.2)	IV.D1.R-40	3.1.1-070	A
				Cumulative fatigue damage	TLAA	IV.D1.R-46	3.1.1-002	C

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator - Aging Management Evaluation

Subcomponent	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tube support plate	FD;SS	Stainless steel	(E) Treated water >60°C (>140°F)	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-384	3.1.1-071	A
					Water Chemistry (B2.1.2)	IV.D1.RP-384	3.1.1-071	A
				Cumulative fatigue damage	TLAA	IV.C2.R-18	3.1.1-005	C
				Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-226	3.1.1-071	A
					Water Chemistry (B2.1.2)	IV.D1.RP-226	3.1.1-071	A
					Steam Generators (B2.1.10)	IV.D1.RP-225	3.1.1-076	A
Tubesheet	PB	Steel with nickel alloy cladding	(I) Reactor coolant	Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	A
				Loss of material	Steam Generators (B2.1.10)	IV.D1.R-436	3.1.1-127	A
					Water Chemistry (B2.1.2)	IV.D1.R-436	3.1.1-127	A
			(E) Treated water	Loss of material	Steam Generators (B2.1.10)	IV.D1.RP-161	3.1.1-072	C
					Water Chemistry (B2.1.2)	IV.D1.RP-161	3.1.1-072	C
Tube-to-tubesheet weld	SS	Nickel alloy	(E) Reactor coolant	Cracking	Steam Generators (B2.1.10)	IV.D1.RP-385	3.1.1-025	A
					Water Chemistry (B2.1.2)	IV.D1.RP-385	3.1.1-025	A
				Cumulative fatigue damage	TLAA	IV.D1.R-221	3.1.1-008	A

Table 3.1.2-4 Plant-Specific Notes:

1. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program is used instead of the Steam Generators (B2.1.10) program to manage loss of material due to boric acid corrosion for the primary inlet and outlet nozzle and safe end.
2. The Steam Generators (B2.1.10) program is used instead of the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program to manage cracking due to stress corrosion cracking for the channel head stainless steel cladding.
3. Wear of steam generator tubes at the tube support plates is a plant-specific TLAA, evaluated in Steam Generator Tube Wear Evaluation (4.7.8).
4. The One-Time Inspection (B2.1.20) program, using magnetic particle test intended to cover essentially 100 percent of the total weld length of each weld on each steam generator, will verify the effectiveness of the Water Chemistry (B2.1.2) program to manage loss of material for the upper shell-to-transition cone girth weld and the new transition cone closure weld.
5. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program is used instead of the Steam Generators (B2.1.10) program to manage cracking and loss of material for the feedwater nozzle thermal sleeve.

Tables 3.1.2-1 through 3.1.2-4 Industry Standard Notes:

A. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

B. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.

C. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

D. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to the NUREG-2191 AMP.

E. Consistent with NUREG-2191 item for 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.

G. Environment not in NUREG-2191 for this component and material.

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.

J. Neither the component nor the material and environment combination is evaluated in NUREG-2191.

3.2 AGING MANAGEMENT OF ENGINEERED SAFETY FEATURES

3.2.1 INTRODUCTION

This section provides the results of the aging management review for those components identified in Section 2.3.2, Engineered Safety Features, as being subject to aging management review. The systems, or portions of systems, which are addressed in this section are described in the indicated sections.

- Quench Spray (Section 2.3.2.1)
- Recirculation Spray (Section 2.3.2.2)
- Residual Heat Removal (Section 2.3.2.3)
- Safety Injection (Section 2.3.2.4)

3.2.2 RESULTS

The following tables summarize the results of the aging management review for Engineered Safety Features Systems.

- Table 3.2.2-1, Engineering Safety Features - Quench Spray - Aging Management Evaluation
- Table 3.2.2-2, Engineering Safety Features - Recirculation Spray - Aging Management Evaluation
- Table 3.2.2-3, Engineering Safety Features - Residual Heat Removal - Aging Management Evaluation
- Table 3.2.2-4, Engineering Safety Features - Safety Injection - Aging Management Evaluation

3.2.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.2.2.1.1 Quench Spray

Materials

The materials of construction for the quench spray system component types are:

- Copper alloy (>15% Zn)
- Non-metallic thermal insulation
- Stainless steel
- Steel

Environment

The quench spray system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Concrete
- Condensation
- Gas
- Soil
- Treated borated water
- Treated water
- Underground

Aging Effects Requiring Management

The following aging effects, associated with the quench spray system, require management:

- Cracking
- Loss of material
- Loss of preload
- Reduced thermal insulation resistance

Aging Management Programs

The following aging management programs manage the aging effects for the quench spray system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.27)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- One-Time Inspection (B2.1.20)
- Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)
- Water Chemistry (B2.1.2)

3.2.2.1.2 Recirculation Spray

Materials

The materials of construction for the recirculation spray system component types are:

- Copper alloy (>15% Zn)
- Stainless steel
- Steel

Environment

The recirculation spray system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Concrete
- Condensation
- Soil
- Treated borated water
- Treated water
- Underground
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the recirculation spray system, require management:

- Cracking
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following aging management programs manage the aging effects for the recirculation spray system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.27)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- One-Time Inspection (B2.1.20)
- Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)
- Water Chemistry (B2.1.2)

3.2.2.1.3 Residual Heat Removal

Materials

The materials of construction for the residual heat removal system component types are:

- Copper alloy
- Stainless steel
- Steel

Environment

The residual heat removal system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air with borated water leakage
- Closed–cycle cooling water
- Concrete
- Reactor coolant
- Soil
- Treated borated water
- Treated borated water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects, associated with the residual heat removal system, require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following aging management programs manage the aging effects for the residual heat removal system component types:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)
- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.27)
- Closed Treated Water Systems (B2.1.12)
- Compressed Air Monitoring (B2.1.14)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.2.2.1.4 Safety Injection

Materials

The materials of construction for the safety injection system component types are:

- Glass
- Non-metallic thermal insulation
- Stainless steel
- Steel
- Steel with stainless steel cladding

Environment

The safety injection system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Concrete
- Gas
- Reactor coolant
- Soil
- Treated borated water
- Treated borated water >60°C (>140°F)
- Treated water
- Underground
- Waste 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
- Reduced thermal insulation resistance

Aging Management Programs

The following aging management programs manage the aging effects for the safety injection system component types:

- ASME Code Class 1 Small-Bore Piping (B2.1.22)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)
- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.27)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.2.2.2 Further Evaluation of Aging Management as Recommended by NUREG-2192

NUREG-2192 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 evaluations are addressed in the following sections.

3.2.2.2.1 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue or cyclical loading parameters may be time-limited aging analyses (TLAAs), as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.3, "Metal Fatigue," or Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," of this SRP SLR. For plant-specific cumulative usage factor calculations that are based on stress-based input methods, the methods are to be appropriately defined and discussed in the applicable TLAAs.

[3.2.1-001] – Fatigue of Engineered Safety Features components is a time-limited aging analysis (TLAA), as defined in 10 CFR 54.3. The evaluation of this TLAA is addressed in Section 4.3.3, USAS (ANSI) B31.1 Allowable Stress Analyses.

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 atmospheric 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 NAPS operating experience identified cracking of stainless steel piping in a valve pit and in a pipe tunnel in which groundwater inleakage to the areas wetted the piping with contaminants that supported stress corrosion cracking. Surface discoloration was also noted that may represent loss of material. The external environment in these below-grade areas where groundwater inleakage may wet components is called “underground” in the SLRA. Loss of material of stainless steel in underground environments requires aging management because the same contaminants that support cracking of stainless steel also support loss of material. The operating experience review did not identify loss of material due to pitting or crevice corrosion for stainless steel or nickel alloy piping, piping components, or tanks in other air environments (air-indoor uncontrolled, air-outdoor, or condensation). Loss of material for stainless steel components in an underground environment will be managed by the Buried and Underground Piping and Tanks (B2.1.27) program. The absence of the aging effect in other air environments will be confirmed by the One-Time Inspection (B2.1.20) program or by one-time inspections directed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program.

[3.2.1-004] – Loss of material of stainless steel components exposed to air-indoor uncontrolled or air-outdoor is managed by the One-Time Inspection (B2.1.20) program.

[3.2.1-048] – Loss of material of stainless steel components exposed to air-indoor uncontrolled (internal) is managed by the One-Time Inspection (B2.1.20) program.

[3.2.1-099] – Loss of material of stainless steel tanks exposed to air-indoor uncontrolled is managed by the One-Time Inspection (B2.1.20) program.

[3.2.1-106] – Loss of material of stainless steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to air-outdoor or condensation is managed by one-time inspections directed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program.

[3.2.1-107] – Loss of material of stainless steel components exposed to condensation is managed by the One-Time Inspection (B2.1.20) program.

[3.2.1-112] – Loss of material of stainless steel components exposed to an underground environment is managed by the Buried and Underground Piping and Tanks (B2.1.27) program.

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.

Not applicable - BWR only.

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 atmospheric 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.

A review of NAPS operating experience identified cracking of stainless steel piping in a valve pit and in a pipe tunnel in which groundwater inleakage to the areas wetted the piping with contaminants that supported stress corrosion cracking of heat-sensitized material adjacent to piping welds. The external environment in these below-grade areas where groundwater inleakage may wet components is called “underground” in the SLRA. The operating experience review did not identify cracking of stainless steel components in other air environments (air-indoor uncontrolled, air-outdoor, or condensation). Cracking of stainless steel components in an underground environment will be managed by the Buried and Underground Piping and Tanks (B2.1.27) program. The absence of the aging effect in other air environments will be confirmed by the One-Time Inspection (B2.1.20) program or by one-time inspections directed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program.

[3.2.1-007] – Cracking of stainless steel components exposed to air-indoor uncontrolled or air-outdoor is managed by the One-Time Inspection (B2.1.20) program.

[3.2.1-080] – Cracking of stainless steel components exposed to an underground environment is managed by the Buried and Underground Piping and Tanks (B2.1.27) program.

[3.2.1-103] – Cracking of stainless steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to air-outdoor or condensation is managed by one-time inspections directed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program.

[3.2.1-108] – Cracking of stainless steel components exposed to condensation is managed by the One-Time Inspection (B2.1.20) program.

3.2.2.2.5 Quality Assurance for Aging Management of Nonsafety-Related Components

Quality Assurance provisions applicable to subsequent license renewal are discussed in Appendix B1.3, Quality Assurance Program and Administrative Controls.

3.2.2.2.6 Ongoing Review of Operating Experience

The operating experience process and acceptance criteria are described in Appendix B1.4, Operating Experience.

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.

Not applicable. A review of NAPS operating experience confirms that loss of material due to recurring internal corrosion is not an aging effect that requires management for the Engineered Safety Features systems.

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.

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, 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.

Not applicable. NAPS has no in-scope aluminum components in the Engineered Safety Features systems.

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.

NAPS has no in-scope steel piping, piping components exposed to concrete in the Engineered Safety Features systems, and has no in-scope stainless steel piping components exposed to concrete that is not exposed to groundwater in the Engineered Safety Features systems.

Loss of material and cracking can occur for stainless steel piping components with an external environment of concrete that are potentially exposed to groundwater. Embedded piping that exits concrete into soil or underground environments are potentially exposed to groundwater. Loss of material and cracking for stainless steel components with an external environment of concrete that exit the concrete into soil or underground is managed by the Buried and Underground Piping and Tanks (B2.1.27) program as identified in [3.2.1-053] and [3.2.1-078]

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 atmospheric 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.

Not applicable. NAPS has no in-scope aluminum components in the Engineered Safety Features systems.

Results Tables: Engineered Safety Features Systems

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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 of stainless steel piping, piping components exposed to reactor coolant and treated borated water >60°C (>140°F) is a TLAA. See further evaluation 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. Loss of material of stainless steel components exposed to air - indoor uncontrolled and air - outdoor is managed by the One-Time Inspection (B2.1.20) program. See further evaluation 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	Consistent with NUREG-2191. No Engineered Safety Features components are aligned to this item. Only components in Auxiliary Systems (chemical and volume control system) are aligned to this item.
3.2.1-006	Metallic drywell and suppression chamber spray system (internal surfaces): flow orifice; spray nozzles exposed to air – indoor uncontrolled, condensation	Loss of material due to general, pitting, crevice corrosion; flow blockage due to fouling	AMP XI.M32, One-Time Inspection, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Yes (SRP-SLR Section 3.2.2.2.3)	Not applicable - BWR only.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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. Cracking of stainless steel components exposed to air - indoor uncontrolled and air - outdoor is managed by the One-Time Inspection (B2.1.20) program. In addition to Engineered Safety Features, components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant, reactor vessel, steam generator) are aligned to this item. See further evaluation 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. In addition to Engineered Safety Features, components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item.
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.
3.2.1-010	Cast austenitic stainless steel piping, piping components exposed to treated borated water >250°C (>482°F), treated water >250°C (>482°F)	Loss of fracture toughness due to thermal aging embrittlement	AMP XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	No	Not applicable. NAPS has no in-scope cast austenitic stainless steel piping, piping components exposed to treated borated water >250°C (>482°F), treated water >250°C (>482°F) in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope steel piping, piping components exposed to steam, treated water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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. NAPS has no in-scope high-strength steel closure bolting exposed to air, soil, underground in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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.
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.
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 applicable. NAPS has no in-scope steel piping, piping components exposed to treated water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-017	Aluminum piping, piping components exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable. NAPS has no in-scope aluminum piping, piping components exposed to treated water, treated borated water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-020	Stainless steel, steel (with stainless steel or nickel alloy cladding) piping, piping components, tanks exposed to treated borated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191. In addition to Engineered Safety Features, components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item.
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. In addition to Engineered Safety Features, components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) and Auxiliary Systems (boron recovery) are aligned to this item.
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. NAPS has no in-scope steel heat exchanger components, piping, piping components exposed to raw water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope stainless steel piping, piping components exposed to raw water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope stainless steel heat exchanger components exposed to raw water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope stainless steel, steel heat exchanger tubes exposed to raw water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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. NAPS has no in-scope stainless steel piping, piping components exposed to closed-cycle cooling water >60°C (>140°F) in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope steel piping, piping components exposed to closed-cycle cooling water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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.
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. In addition to Engineered Safety Features, components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item.
3.2.1-032	Copper alloy heat exchanger components, piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, Closed Treated Water Systems	No	Not applicable. NAPS has no in-scope copper alloy heat exchanger components, piping, piping components exposed to closed-cycle cooling water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. In addition to Engineered Safety Features, components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-034	Copper alloy (>15% Zn or >8% Al) piping, piping components, heat exchanger components exposed to closed-cycle cooling water, treated water	Loss of material due to selective leaching	AMP XI.M33, Selective Leaching	No	Not applicable. NAPS has no in-scope copper alloy (>15% Zn or >8% Al) piping, piping components, heat exchanger components exposed to closed-cycle cooling water, treated water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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	Not applicable. NAPS has no in-scope gray cast iron motor cooler exposed to closed-cycle cooling water, treated water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope gray cast iron, ductile iron piping, piping components exposed to closed-cycle cooling water, treated water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope gray cast iron, ductile iron piping, piping components exposed to soil in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-038	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Not applicable. NAPS has no in-scope elastomer piping, piping components, seals exposed to air, condensation in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-042	Aluminum piping, piping components, tanks exposed to air, condensation (external)	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. NAPS has no in-scope aluminum piping, piping components, tanks exposed to air, condensation (external) in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-043	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. NAPS has no in-scope elastomer piping, piping components, seals exposed to air, condensation in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. In addition to Engineered Safety Features, components in Steam and Power Conversion System (auxiliary boilers, auxiliary steam, blowdown, condensate, extraction steam, feedwater, main steam, and steam drains) are aligned to this item.
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. NAPS has no in-scope steel encapsulation components exposed to air – indoor uncontrolled in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-046	Steel piping, piping components exposed to condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. NAPS has no in-scope steel piping, piping components exposed to condensation in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope steel encapsulation components exposed to air with borated water leakage in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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. Loss of material of stainless steel piping, piping components exposed to air (internal) is managed by the One-Time Inspection (B2.1.20) program. See further evaluation 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. NAPS has no in-scope steel piping, piping components exposed to lubricating oil in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-050	Copper alloy, stainless steel piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M39, Lubricating Oil Analysis, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191. No Engineered Safety Features components are aligned to this item. Only components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item.
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. NAPS has no in-scope steel, copper alloy, stainless steel heat exchanger tubes with a heat transfer function exposed to lubricating oil in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope steel piping, piping components exposed to soil, concrete, underground in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191.
3.2.1-054	Stainless steel, nickel alloy piping, piping components greater than or equal to 4 NPS exposed to treated water >93°C (>200°F)	Cracking due to SCC, IGSCC	AMP XI.M7, BWR Stress Corrosion Cracking, and AMP XI.M2, Water Chemistry	No	Not applicable - BWR only.
3.2.1-055	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.2.2.2.9)	Not applicable. NAPS has no in-scope steel piping, piping components exposed to concrete in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-056	Aluminum piping, piping components, tanks exposed to air, condensation (internal)	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. NAPS has no in-scope aluminum piping, piping components, tanks exposed to air, condensation (internal) in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-057	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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. The air with borated water leakage environment was not applied to copper alloy in the Engineered Safety Features systems because the aging evaluation is equivalent to that for copper alloy in air - indoor uncontrolled, which is addressed by item 3.2.1-057. NAPS does not have copper alloy (>8% Al) in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-059	Galvanized steel ducting, ducting components, piping, piping components exposed to air – indoor controlled	None	None	No	Not applicable. NAPS has no in-scope galvanized steel ducting, ducting components, piping, piping components exposed to air – indoor controlled in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. In addition to Engineered Safety Features, components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item.
3.2.1-062	Nickel alloy piping, piping components exposed to air with borated water leakage	None	None	No	Not applicable. NAPS has no in-scope nickel alloy piping, piping components exposed to air with borated water leakage in the Engineered Safety Features systems. 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.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-064	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Consistent with NUREG-2191. In addition to Engineered Safety Features, components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item.
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. Wall thinning due to erosion is not an aging effect requiring management for metallic piping components exposed to treated water or treated borated water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. Recurring internal corrosion has not been identified by a search of NAPS operating experience for piping, piping components or tanks exposed to raw water or waste water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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 exceptions. Exceptions apply to the NUREG-2191 recommendations for Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program implementation.
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. NAPS has no in-scope steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to soil, concrete, air, condensation in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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. NAPS has no in-scope insulated steel piping, piping components or tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air-outdoor or condensation in the Engineered Safety Features systems. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable. The associated NUREG-2191 aging items are not used.
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 exceptions. Exceptions apply to the NUREG-2191 recommendations for Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program implementation.
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	Consistent with NUREG-2191. No Engineered Safety Features components are aligned to this item. Only components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item.
3.2.1-072	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, treated borated water	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage; loss of material or cracking for cementitious coatings/linings	AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	No	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program implementation. No Engineered Safety Features components are aligned to this item. Only components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) and Auxiliary Systems (chemical and volume control) are aligned to this item.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-073	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	No	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program implementation. No Engineered Safety Features components are aligned to this item. Only components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) and Auxiliary Systems (chemical and volume control) are aligned to this item.
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. NAPS has no in-scope 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 in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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	Consistent with NUREG-2191.
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	Consistent with NUREG-2191.
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.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-080	Stainless steel underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.M41, Buried and Underground Piping and Tanks, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.4)	Consistent with NUREG-2191. Cracking of stainless steel underground piping, piping components is managed by the Buried and Underground Piping and Tanks (B2.1.27) program. See further evaluation in Section 3.2.2.2.4.
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. In addition to Engineered Safety Features, components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item.
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.
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. NAPS has no in-scope steel components exposed to treated water, treated borated water, raw water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. Aging of stainless steel piping, piping components exposed to concrete in the Engineered Safety Features systems is addressed in rows 3.2.1-053 and 3.2.1-078. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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. NAPS has no in-scope steel, stainless steel piping, piping components exposed to raw water (for components not covered by NRC GL 89-13) in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-099	Stainless steel, nickel alloy tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.2)	Consistent with NUREG-2191. Loss of material of stainless steel tanks exposed to air - indoor uncontrolled is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.2.2.2.2.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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 applicable. NAPS has no in-scope aluminum piping, piping components, tanks exposed to air, condensation (internal), raw water, waste water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-101	Aluminum piping, piping components, tanks exposed to air, condensation (external)	Cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.8)	Not applicable. NAPS has no in-scope aluminum piping, piping components, tanks exposed to air, condensation (external) in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-102	Aluminum tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air, condensation, soil, concrete, raw water, waste water	Cracking due to SCC	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.8)	Not applicable. NAPS has no in-scope 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 in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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 exceptions. Exceptions apply to the NUREG-2191 recommendations for Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program implementation. Cracking of stainless steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to air - outdoor or condensation is managed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program. See further evaluation 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. NAPS has no in-scope aluminum tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to soil, concrete in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-105	Aluminum tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.10)	Not applicable. NAPS has no in-scope aluminum tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to air, condensation in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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 exceptions. Exceptions apply to the NUREG-2191 recommendations for Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program implementation. Loss of material of stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air - outdoor, condensation is managed by the Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program. See further evaluation in Section 3.2.2.2.2.
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. Loss of material of stainless steel components exposed to condensation is managed by the One-Time Inspection (B2.1.20) program. See further evaluation 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. Cracking of stainless steel components exposed to condensation is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.2.2.2.4.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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. NAPS has no in-scope insulated aluminum piping, piping components, tanks exposed to air, condensation in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope aluminum underground piping, piping components, tanks in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope aluminum underground piping, piping components, tanks in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-112	Stainless steel, nickel alloy underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M41, Buried and Underground Piping and Tanks, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.2.2.2.2)	Consistent with NUREG-2191. Loss of material of stainless steel underground piping, piping components is managed by the Buried and Underground Piping and Tanks (B2.1.27) program. See further evaluation in Section 3.2.2.2.2.
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. NAPS has no in-scope stainless steel, nickel alloy piping, piping components exposed to treated water >60°C (>140°F) in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope titanium heat exchanger tubes exposed to treated water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to treated water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope titanium heat exchanger tubes exposed to closed-cycle cooling water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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. NAPS has no in-scope 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 in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope insulated aluminum piping, piping components, tanks exposed to air, condensation in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-120	Aluminum piping, piping components, tanks exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. NAPS has no in-scope aluminum piping, piping components, tanks exposed to soil, concrete in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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. NAPS has no in-scope aluminum piping, piping components, tanks exposed to raw water, waste water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-122	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Not applicable. NAPS has no in-scope elastomer piping, piping components, seals exposed to air in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-123	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. NAPS has no in-scope elastomer piping, piping components, seals exposed to air in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-124	Aluminum piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not applicable. NAPS has no in-scope aluminum piping, piping components, tanks exposed to air with borated water leakage in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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	Consistent with NUREG-2191.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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. NAPS has no in-scope titanium, super austenitic piping, piping components, tanks, closure bolting exposed to soil, concrete, underground in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
3.2.1-127	Copper alloy piping, piping components exposed to concrete	None	None	No	Not applicable. NAPS has no in-scope copper alloy piping, piping components exposed to concrete in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope copper alloy piping, piping components exposed to soil, underground in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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 exceptions. Exceptions apply to the NUREG-2191 recommendations for Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program implementation.
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	Consistent with NUREG-2191. No Engineered Safety Features components are aligned to this item. Only components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item.
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. NAPS has no in-scope aluminum piping, piping components exposed to raw water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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. NAPS has no in-scope titanium piping, piping components, heat exchanger components exposed to raw water in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope polymeric piping, piping components, ducting, ducting components, seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, soil in the Engineered Safety Features systems. The associated NUREG-2191 aging items are not used.

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Results Tables: Engineered Safety Features AMR Results

Table 3.2.2-1 Engineering Safety Features - Quench Spray - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB;SI	Stainless steel	(E) Air – outdoor	Loss of material	Bolting Integrity (B2.1.9)	V.E.E-02	3.2.1-014	A
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A
			(E) Condensation	Loss of material	Bolting Integrity (B2.1.9)	V.E.E-02	3.2.1-014	A
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	V.E.E-02	3.2.1-014	A
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A
			(E) Air – outdoor	Loss of material	Bolting Integrity (B2.1.9)	V.E.E-02	3.2.1-014	A
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.E-28	3.2.1-009	A
			(E) Condensation	Loss of material	Bolting Integrity (B2.1.9)	V.E.E-02	3.2.1-014	A
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A
Heat exchanger (refueling water refrigeration unit - base mounted evaporator/cooler)	SI	Stainless steel	(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	V.E.E-451b	3.2.1-108	C
				Loss of material	One-Time Inspection (B2.1.20)	V.E.E-450b	3.2.1-107	C
			(I) Gas	None	None	V.F.EP-22	3.2.1-063	C
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
Insulation (safety-related heat traced components)	TI	Non-metallic thermal insulation	(E) Air – outdoor	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-422	3.2.1-087	A
Orifice	PB;RF;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-81b	3.2.1-048	A
			(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	V.E.E-451b	3.2.1-108	A
				Loss of material	One-Time Inspection (B2.1.20)	V.E.E-450b	3.2.1-107	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A

Table 3.2.2-1 Engineering Safety Features - Quench Spray - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-81b	3.2.1-048	A
			(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	V.E.E-451b	3.2.1-108	A
				Loss of material	One-Time Inspection (B2.1.20)	V.E.E-450b	3.2.1-107	A
			(E) Soil	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-420	3.2.1-078	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.EP-72	3.2.1-053	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
			(E) Underground	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-423b	3.2.1-080	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-455b	3.2.1-112	A
Piping, piping components (exiting concrete into soil)	PB	Stainless steel	(E) Concrete	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-420	3.2.1-078	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.EP-72	3.2.1-053	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
Pump casing (chemical addition tank recirculation)	SI	Stainless steel	(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A

Table 3.2.2-1 Engineering Safety Features - Quench Spray - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (quench spray)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	V.E.E-451b	3.2.1-108	A
				Loss of material	One-Time Inspection (B2.1.20)	V.E.E-450b	3.2.1-107	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
Pump casing (refueling water recirculation)	LB	Stainless steel	(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	V.E.E-451b	3.2.1-108	A
				Loss of material	One-Time Inspection (B2.1.20)	V.E.E-450b	3.2.1-107	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
Spray nozzle	SP	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	V.F.EP-10	3.2.1-057	A, 1
			(I) Air – indoor uncontrolled	None	None	V.F.EP-10	3.2.1-057	A, 1
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.EP-38	3.2.1-008	A
Strainer body	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	V.E.E-451b	3.2.1-108	A
				Loss of material	One-Time Inspection (B2.1.20)	V.E.E-450b	3.2.1-107	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
Strainer element	FLT	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A

Table 3.2.2-1 Engineering Safety Features - Quench Spray - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (chemical addition)	PB	Stainless steel	(E) Air – outdoor	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-446a	3.2.1-103	B
				Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-449a	3.2.1-106	B
			(I) Treated water	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.A.E-404	3.2.1-070	B
Tank (refueling water storage)	PB	Stainless steel	(E) Concrete	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-405	3.2.1-067	B
				Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-472	3.2.1-129	B
			(E) Condensation	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-446a	3.2.1-103	B
				Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-449a	3.2.1-106	B
			(I) Treated borated water	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.A.E-404	3.2.1-070	B
Valve body	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-81b	3.2.1-048	A
			(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	V.E.E-451b	3.2.1-108	A
				Loss of material	One-Time Inspection (B2.1.20)	V.E.E-450b	3.2.1-107	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A

Table 3.2.2-1 Plant-Specific Notes:

1. Spray nozzles are not wetted and are near the top of Containment, not exposed to potential leakage through insulation that could carry contaminants such as ammonia compounds that support cracking.

Table 3.2.2-2 Engineering Safety Features - Recirculation Spray - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	Bolting Integrity (B2.1.9)	V.E.E-421	3.2.1-079	A
				Loss of material	Bolting Integrity (B2.1.9)	V.E.E-02	3.2.1-014	A
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A
			(E) Treated water	Loss of material	Bolting Integrity (B2.1.9)	V.E.E-418	3.2.1-076	A
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A
			(E) Waste water	Cracking	Bolting Integrity (B2.1.9)	VII.I.A-426	3.3.1-145	A, 3
				Loss of material	Bolting Integrity (B2.1.9)	V.E.E-418	3.2.1-076	A, 3
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A, 3
		Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	V.E.E-02	3.2.1-014	A
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.E-28	3.2.1-009	A
			(E) Condensation	Loss of material	Bolting Integrity (B2.1.9)	V.E.E-02	3.2.1-014	A
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-468	3.2.1-125	A
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A
Heat exchanger (casing cooling tank chiller - shell)	LB	Stainless steel	(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	V.E.E-451b	3.2.1-108	C
				Loss of material	One-Time Inspection (B2.1.20)	V.E.E-450b	3.2.1-107	C
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
Heat exchanger (recirculation spray - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	C
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-81b	3.2.1-048	C
Heat exchanger (recirculation spray - shell)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	C
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-81b	3.2.1-048	C

Table 3.2.2-2 Engineering Safety Features - Recirculation Spray - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (recirculation spray - tube)	HT;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	C
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-81b	3.2.1-048	C
Heat exchanger (recirculation spray - tubesheet)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	C
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-81b	3.2.1-048	C
Heat exchanger (seal cooler - tube)	HT;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	C
				Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-424	3.2.1-081	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	VIII.F.SP-96	3.4.1-018	A
					Water Chemistry (B2.1.2)	VIII.F.SP-96	3.4.1-018	A
Orifice	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-81b	3.2.1-048	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A

Table 3.2.2-2 Engineering Safety Features - Recirculation Spray - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-81b	3.2.1-048	A
			(E) Concrete	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-420	3.2.1-078	A, 2
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.EP-72	3.2.1-053	A, 2
			(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	V.E.E-451b	3.2.1-108	A
				Loss of material	One-Time Inspection (B2.1.20)	V.E.E-450b	3.2.1-107	A
			(E) Soil	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-420	3.2.1-078	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.EP-72	3.2.1-053	A
			(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
			(E) Underground	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-423b	3.2.1-080	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-455b	3.2.1-112	A
			(E) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-411	3.3.1-135	A, 3

Table 3.2.2-2 Engineering Safety Features - Recirculation Spray - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components (exiting concrete into soil)	PB	Stainless steel	(E) Concrete	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-420	3.2.1-078	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.EP-72	3.2.1-053	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
Pump casing (casing cooling tank recirculation)	LB	Stainless steel	(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	V.E.E-451b	3.2.1-108	A
				Loss of material	One-Time Inspection (B2.1.20)	V.E.E-450b	3.2.1-107	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
Pump casing (casing cooling)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
Pump casing (recirculation spray)	PB	Stainless steel	(E) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
Spray nozzle	SP	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	V.F.EP-10	3.2.1-057	A, 1
			(I) Air – indoor uncontrolled	None	None	V.F.EP-10	3.2.1-057	A, 1
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.EP-38	3.2.1-008	A
Strainer body	LB	Stainless steel	(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	V.E.E-451b	3.2.1-108	A
				Loss of material	One-Time Inspection (B2.1.20)	V.E.E-450b	3.2.1-107	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
Strainer element (containment sump)	FLT	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A

Table 3.2.2-2 Engineering Safety Features - Recirculation Spray - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (casing cooling)	PB	Stainless steel	(E) Concrete	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-405	3.2.1-067	B
				Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-472	3.2.1-129	B
			(E) Condensation	Cracking	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-446a	3.2.1-103	B
				Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-449a	3.2.1-106	B
			(I) Treated borated water	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	V.D1.E-404	3.2.1-070	B
Tank (seal accumulator)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.E.E-442a	3.2.1-099	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-81b	3.2.1-048	A
			(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	V.E.E-451b	3.2.1-108	A
				Loss of material	One-Time Inspection (B2.1.20)	V.E.E-450b	3.2.1-107	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.A.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.A.EP-41	3.2.1-022	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
			(E) Underground	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-423b	3.2.1-080	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-455b	3.2.1-112	A

Table 3.2.2-2 Plant-Specific Notes:

1. Spray nozzles are not wetted and are near the top of Containment, not exposed to potential leakage through insulation that could carry contaminants such as ammonia compounds that support cracking.
2. Piping exits concrete into underground environment, and is potentially exposed to groundwater.
3. The recirculation suction sump is partially filled with demineralized water after outages. The sump is assumed to collect contaminants during normal operation, resulting in a waste water environment for external surfaces of suction piping and bolting within the sump.

Table 3.2.2-3 Engineering Safety Features - Residual Heat Removal - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	V.E.E-02	3.2.1-014	A
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.E-28	3.2.1-009	A
Heat exchanger (residual heat removal - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	C
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	C
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.D1.E-12	3.2.1-020	C
					Water Chemistry (B2.1.2)	V.D1.E-12	3.2.1-020	C
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
Heat exchanger (residual heat removal - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-44	3.2.1-040	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.E-28	3.2.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	V.D1.EP-92	3.2.1-030	A
Heat exchanger (residual heat removal - tube)	HT;PB	Stainless steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	V.D1.EP-93	3.2.1-031	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	V.D1.EP-96	3.2.1-033	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.D1.E-12	3.2.1-020	C
					Water Chemistry (B2.1.2)	V.D1.E-12	3.2.1-020	C
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	V.D1.E-20	3.2.1-019	A
					Water Chemistry (B2.1.2)	V.D1.E-20	3.2.1-019	A
Heat exchanger (residual heat removal - tubesheet)	PB	Stainless steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	V.D1.EP-93	3.2.1-031	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.D1.E-12	3.2.1-020	C
					Water Chemistry (B2.1.2)	V.D1.E-12	3.2.1-020	C
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A

Table 3.2.2-3 Engineering Safety Features - Residual Heat Removal - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (seal cooler - housing)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-44	3.2.1-040	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.E-28	3.2.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	V.D1.EP-92	3.2.1-030	A
Heat exchanger (seal cooler - tube)	HT;PB	Stainless steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	V.D1.EP-93	3.2.1-031	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	V.D1.EP-96	3.2.1-033	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	V.D1.E-20	3.2.1-019	A
					Water Chemistry (B2.1.2)	V.D1.E-20	3.2.1-019	A
Orifice	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.D1.E-12	3.2.1-020	A
					Water Chemistry (B2.1.2)	V.D1.E-12	3.2.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A

Table 3.2.2-3 Engineering Safety Features - Residual Heat Removal - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Copper alloy	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	None	None	V.F.EP-10	3.2.1-057	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-81b	3.2.1-048	A
			(E) Soil	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-420	3.2.1-078	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.EP-72	3.2.1-053	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.D1.E-12	3.2.1-020	A
					Water Chemistry (B2.1.2)	V.D1.E-12	3.2.1-020	A
				Cumulative fatigue damage	TLAA	V.D1.E-13	3.2.1-001	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
Piping, piping components (Class 1)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	A
				Cumulative fatigue damage	TLAA	V.D1.E-13	3.2.1-001	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Piping, piping components (exiting concrete into soil)	PB	Stainless steel	(E) Concrete	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-420	3.2.1-078	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.EP-72	3.2.1-053	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A

Table 3.2.2-3 Engineering Safety Features - Residual Heat Removal - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (residual heat removal)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.D1.E-12	3.2.1-020	A
					Water Chemistry (B2.1.2)	V.D1.E-12	3.2.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
Valve body	PB	Copper alloy	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	None	None	V.F.EP-10	3.2.1-057	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.D1.E-12	3.2.1-020	A
					Water Chemistry (B2.1.2)	V.D1.E-12	3.2.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
Valve body (Class 1)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	A
				Cumulative fatigue damage	TLAA	V.D1.E-13	3.2.1-001	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.2.2-3 Plant-Specific Notes: None

Table 3.2.2-4 Engineering Safety Features - Safety Injection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	Bolting Integrity (B2.1.9)	V.E.E-421	3.2.1-079	A
				Loss of material	Bolting Integrity (B2.1.9)	V.E.E-02	3.2.1-014	A
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A
			(E) Treated borated water	Loss of material	Bolting Integrity (B2.1.9)	V.E.E-418	3.2.1-076	A
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A
			(E) Waste water	Cracking	Bolting Integrity (B2.1.9)	VII.I.A-426	3.3.1-145	A, 2
				Loss of material	Bolting Integrity (B2.1.9)	V.E.E-418	3.2.1-076	A, 2
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A, 2
		Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	V.E.E-02	3.2.1-014	A
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.E-28	3.2.1-009	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-468	3.2.1-125	A
				Loss of preload	Bolting Integrity (B2.1.9)	V.E.EP-116	3.2.1-015	A
Insulation (safety-related heat traced components)	TI	Non-metallic thermal insulation	(E) Air – indoor uncontrolled	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-422	3.2.1-087	A
			(E) Air – outdoor	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-422	3.2.1-087	A
Orifice	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.D1.E-12	3.2.1-020	A
					Water Chemistry (B2.1.2)	V.D1.E-12	3.2.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A

Table 3.2.2-4 Engineering Safety Features - Safety Injection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-81b	3.2.1-048	A
			(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(E) Concrete	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-420	3.2.1-078	A, 1
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.EP-72	3.2.1-053	A, 1
			(I) Gas	None	None	V.F.EP-22	3.2.1-063	A
			(E) Soil	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-420	3.2.1-078	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.EP-72	3.2.1-053	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.D1.E-12	3.2.1-020	A
					Water Chemistry (B2.1.2)	V.D1.E-12	3.2.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
			(E) Underground	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-423b	3.2.1-080	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-455b	3.2.1-112	A
			(E) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-411	3.3.1-135	C, 2

Table 3.2.2-4 Engineering Safety Features - Safety Injection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-44	3.2.1-040	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	V.A.E-29	3.2.1-044	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.E-28	3.2.1-009	A
			(I) Gas	None	None	V.F.EP-7	3.2.1-064	A
Piping, piping components (Class 1 <NPS 4)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Reactor coolant	Cracking	ASME Code Class 1 Small-Bore Piping (B2.1.22)	IV.C2.RP-235	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-235	3.1.1-039	A
					Water Chemistry (B2.1.2)	IV.C2.RP-235	3.1.1-039	A
				Cumulative fatigue damage	TLAA	V.D1.E-13	3.2.1-001	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Piping, piping components (Class 1)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	A
				Cumulative fatigue damage	TLAA	V.D1.E-13	3.2.1-001	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Piping, piping components (exiting concrete into soil)	PB	Stainless steel	(E) Concrete	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-420	3.2.1-078	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.EP-72	3.2.1-053	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A

Table 3.2.2-4 Engineering Safety Features - Safety Injection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (hydro test)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
Pump casing (low-head safety injection)	PB	Stainless steel	(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
Sample sink	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
Sight glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	V.F.EP-15	3.2.1-060	A
			(I) Treated water	None	None	V.F.EP-29	3.2.1-060	A
Sight glass (body)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
Strainer body	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-44	3.2.1-040	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.E-28	3.2.1-009	A
			(I) Gas	None	None	V.F.EP-7	3.2.1-064	A
Strainer element	FLT	Stainless steel	(E) Gas	None	None	V.F.EP-22	3.2.1-063	A
Strainer element (containment sump)	FLT	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A

Table 3.2.2-4 Engineering Safety Features - Safety Injection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (boron injection)	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-44	3.2.1-040	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.E-28	3.2.1-009	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.D1.E-12	3.2.1-020	A
					Water Chemistry (B2.1.2)	V.D1.E-12	3.2.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
Tank (hydro test cooling)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
Tank (safety injection accumulator)	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-44	3.2.1-040	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.E-28	3.2.1-009	A
			(I) Gas	None	None	V.F.EP-22	3.2.1-063	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A

Table 3.2.2-4 Engineering Safety Features - Safety Injection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-81b	3.2.1-048	A
			(I) Gas	None	None	V.F.EP-22	3.2.1-063	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	V.D1.E-12	3.2.1-020	A
					Water Chemistry (B2.1.2)	V.D1.E-12	3.2.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
			(E) Underground	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-423b	3.2.1-080	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	V.E.E-455b	3.2.1-112	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.E.E-44	3.2.1-040	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	V.E.E-28	3.2.1-009	A
			(I) Gas	None	None	V.F.EP-7	3.2.1-064	A
Valve body (Class 1)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	A
				Cumulative fatigue damage	TLAA	V.D1.E-13	3.2.1-001	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.2.2-4 Engineering Safety Features - Safety Injection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Venturi	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	V.A.EP-103b	3.2.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-107a	3.2.1-004	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.EP-41	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.D1.EP-41	3.2.1-022	A

Table 3.2.2-4 Plant-Specific Notes:

1. Piping exits concrete into underground environment, and is potentially exposed to groundwater.
2. The recirculation suction sump is partially filled with demineralized water after outages. The sump is assumed to collect contaminants during normal operation, resulting in a waste water environment for external surfaces of suction piping and bolting within the sump.

Tables 3.2.2-1 through 3.2.2-4 Industry Standard Notes:

A. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

B. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.

C. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

D. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to the NUREG-2191 AMP.

E. Consistent with NUREG-2191 item for 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.

G. Environment not in NUREG-2191 for this component and material.

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.

J. Neither the component nor the material and environment combination is evaluated in NUREG-2191.

Intentionally Blank

3.3 AGING MANAGEMENT OF AUXILIARY SYSTEMS

3.3.1 INTRODUCTION

This section provides the results of the aging management review for those components identified in Section 2.3.3, Auxiliary Systems, as being subject to aging management review. The systems, or portions of systems, which are addressed in this section are described in the indicated sections.

- Fuel Pit Cooling (Section 2.3.3.1)
- Refueling Purification (Section 2.3.3.2)
- Primary Grade Water (Section 2.3.3.3)
- Helium Vacuum Drying (Section 2.3.3.4)
- Fuel Handling (Section 2.3.3.5)
- Materials Handling (Section 2.3.3.6)
- Service Water (Section 2.3.3.7)
- Bearing Cooling (Section 2.3.3.8)
- Circulating Water (Section 2.3.3.9)
- Vacuum Priming (Section 2.3.3.10)
- Domestic Water (Section 2.3.3.11)
- Component Cooling (Section 2.3.3.12)
- Neutron Shield Tank Cooling (Section 2.3.3.13)
- Instrument Air (Section 2.3.3.14)
- Service Air (Section 2.3.3.15)
- Primary & Secondary Plant Gas Supplies (Section 2.3.3.16)
- Penetration Electrical (Section 2.3.3.17)
- Leakage Monitoring (Section 2.3.3.18)
- Chemical & Volume Control (Section 2.3.3.19)
- Boron Recovery (Section 2.3.3.20)
- Sampling System (Section 2.3.3.21)
- Incore Instrumentation (Section 2.3.3.22)
- Decontamination (Section 2.3.3.23)
- Drains - Aerated (Section 2.3.3.24)
- Drains - Building Services (Section 2.3.3.25)

- Drains - Gaseous (Section 2.3.3.26)
- Gaseous Waste Disposal (Section 2.3.3.27)
- Liquid & Solid Waste (Radioactive) (Section 2.3.3.28)
- Oil Separation (Section 2.3.3.29)
- Radioactive Waste (Section 2.3.3.30)
- Sanitary Sewage (Section 2.3.3.31)
- Vents - Gaseous (Section 2.3.3.32)
- Containment Vacuum (Section 2.3.3.33)
- Chilled Water (Section 2.3.3.34)
- Heating & Ventilation (Section 2.3.3.35)
- High Radiation Sampling (Section 2.3.3.36)
- Post-Accident Hydrogen Removal (Section 2.3.3.37)
- Radiation Monitoring (Section 2.3.3.38)
- Alternate AC (Section 2.3.3.39)
- Emergency Diesel Generator System (Section 2.3.3.40)
- Security (Section 2.3.3.41)
- Fire Protection (Section 2.3.3.42)
- Containment Access (Section 2.3.3.43)
- Generator Breaker Cooling (Section 2.3.3.44)
- Water Treatment (Section 2.3.3.45)

3.3.2 RESULTS

The following tables summarize the results of the aging management review for Auxiliary Systems.

- Table 3.3.2-1, Auxiliary Systems - Fuel Pit Cooling - Aging Management Evaluation
- Table 3.3.2-2, Auxiliary Systems - Refueling Purification - Aging Management Evaluation
- Table 3.3.2-3, Auxiliary Systems - Primary Grade Water - Aging Management Evaluation
- Table 3.3.2-4, Auxiliary Systems - Helium Vacuum Drying - Aging Management Evaluation
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- Table 3.3.2-44, Auxiliary Systems - Generator Breaker Cooling - Aging Management Evaluation
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3.3.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.3.2.1.1 Fuel Pit Cooling

Materials

The materials of construction for the fuel pit cooling system component types are:

- Stainless steel
- Steel
- Steel with stainless steel cladding

Environment

The fuel pit cooling system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed–cycle cooling water
- Concrete
- Treated borated water

Aging Effects Requiring Management

The following aging effects, associated with the fuel pit cooling system, require management:

- Cracking
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following aging management programs manage the aging effects for the fuel pit cooling system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.3.2.1.2 Refueling Purification

Materials

The materials of construction for the refueling purification system component types are:

- Stainless steel
- Steel

Environment

The refueling purification system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Concrete
- Treated borated water

Aging Effects Requiring Management

The following aging effects, associated with the refueling purification system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the refueling purification system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.3.2.1.3 Primary Grade Water

Materials

The materials of construction for the primary grade water system component types are:

- Copper alloy
- Copper alloy (>15% Zn)
- Stainless steel
- Steel

Environment

The primary grade water system component types 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 primary grade water system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the primary grade water system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.3.2.1.4 Helium Vacuum Drying

Materials

The materials of construction for the helium vacuum drying system component types are:

- Aluminum
- Stainless steel
- Steel

Environment

The helium vacuum drying system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Concrete
- Treated borated water

Aging Effects Requiring Management

The following aging effects, associated with the helium vacuum drying system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the helium vacuum drying system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.3.2.1.5 Fuel Handling

Materials

The materials of construction for the fuel handling system component types are:

- Copper alloy
- Elastomer
- Stainless steel
- Steel

Environment

The fuel handling system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air with borated water leakage
- Treated borated water

Aging Effects Requiring Management

The following aging effects, associated with the fuel handling system, require management:

- Cracking
- Hardening or loss of strength
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the fuel handling system component types:

- 10 CFR Part 50, Appendix J (B2.1.32)
- ASME Section XI, Subsection IWE (B2.1.29)
- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Compressed Air Monitoring (B2.1.14)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.3.2.1.6 Materials Handling

Materials

The materials of construction for the materials handling system component types are:

- Stainless steel
- Steel

Environment

The materials handling system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Treated borated water

Aging Effects Requiring Management

The following aging effects, associated with the materials handling system, require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the materials handling system component types:

- Boric Acid Corrosion (B2.1.4)
- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B2.1.13)
- One-Time Inspection (B2.1.20)
- Structures Monitoring (B2.1.34)
- Water Chemistry (B2.1.2)

3.3.2.1.7 Service Water

Materials

The materials of construction for the service water system component types are:

- Copper alloy
- Copper alloy (>15% Zn)
- Ductile iron
- Elastomer
- Gray cast iron
- Nickel alloy
- Non-metallic thermal insulation
- Polymer
- Stainless steel
- Steel
- Steel with internal coating
- Zinc

Environment

The service water system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Concrete
- Condensation
- Petrolatum corrosion preventive casing filler
- Raw water
- Soil
- Treated water
- Underground
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the service water system, require management:

- Cracking
- Cracking or blistering
- Flow blockage
- Hardening or loss of strength
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduced thermal insulation resistance
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the service water system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.27)
- Compressed Air Monitoring (B2.1.14)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- One-Time Inspection (B2.1.20)
- Open-Cycle Cooling Water System (B2.1.11)
- Selective Leaching (B2.1.21)

3.3.2.1.8 Bearing Cooling

Materials

The materials of construction for the bearing cooling system component types are:

- Copper alloy
- Elastomer
- Glass
- Gray cast iron
- Polymer
- Stainless steel
- Steel

Environment

The bearing cooling system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Raw water
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the bearing cooling system, require management:

- Cracking
- Cracking or blistering
- Flow blockage
- Hardening or loss of strength
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the bearing cooling system component types:

- Bolting Integrity (B2.1.9)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)

3.3.2.1.9 Circulating Water

Materials

The materials of construction for the circulating water system component types are:

- Aluminum
- Copper alloy
- Elastomer
- Fiberglass
- Gray cast iron
- Gray cast iron with internal lining
- Non-metallic thermal insulation
- Stainless steel
- Steel
- Steel with internal coating

Environment

The circulating water system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Concrete
- Raw water

Aging Effects Requiring Management

The following aging effects, associated with the circulating water system, require management:

- Cracking
- Cracking, blistering, loss of material
- Flow blockage
- Hardening or loss of strength
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduced thermal insulation resistance
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the circulating water system component types:

- Bolting Integrity (B2.1.9)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)

3.3.2.1.10 Vacuum Priming

Materials

The materials of construction for the vacuum priming system component types are:

- Copper alloy
- Elastomer
- Glass
- Gray cast iron
- Stainless steel
- Steel

Environment

The vacuum priming system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Condensation
- Raw water
- Steam
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the vacuum priming system, require management:

- Cracking
- Cumulative fatigue damage
- Hardening or loss of strength
- Long-term loss of material
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the vacuum priming system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.3.2.1.11 Domestic Water

Materials

The materials of construction for the domestic water system component types are:

- Copper alloy
- Copper alloy (>15% Zn)
- Elastomer
- Gray cast iron
- Stainless steel
- Steel
- Steel with internal coating

Environment

The domestic water system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Raw water

Aging Effects Requiring Management

The following aging effects, associated with the domestic water system, require management:

- Cracking
- Hardening or loss of strength
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the domestic water system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)

3.3.2.1.12 Component Cooling

Materials

The materials of construction for the component cooling system component types are:

- Copper alloy
- Copper alloy (>15% Zn)
- Elastomer
- Glass
- Gray cast iron
- Stainless steel
- Steel
- Steel with internal coating
- Steel with stainless steel cladding
- Steel with titanium (ASTM Grade 1) cladding
- Titanium (ASTM Grade 2)

Environment

The component cooling system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air with borated water leakage
- Closed–cycle cooling water
- Raw water

Aging Effects Requiring Management

The following aging effects, associated with the component cooling system, require management:

- Cracking
- Flow blockage
- 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 aging management programs manage the aging effects for the component cooling system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- Compressed Air Monitoring (B2.1.14)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- One-Time Inspection (B2.1.20)
- Open-Cycle Cooling Water System (B2.1.11)
- Selective Leaching (B2.1.21)

3.3.2.1.13 Neutron Shield Tank Cooling

Materials

The materials of construction for the neutron shield tank cooling system component types are:

- Stainless steel
- Steel

Environment

The neutron shield tank cooling system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed–cycle cooling water
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the neutron shield tank cooling system, require management:

- Cracking
- Long-term loss of material
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following aging management programs manage the aging effects for the neutron shield tank cooling system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)

3.3.2.1.14 Instrument Air

Materials

The materials of construction for the instrument air system component types are:

- Aluminum
- Copper alloy
- Copper alloy (>15% Zn)
- Glass
- Stainless steel
- Steel

Environment

The instrument air system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air with borated water leakage
- Closed–cycle cooling water
- Condensation
- Raw water

Aging Effects Requiring Management

The following aging effects, associated with the instrument air system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the instrument air system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- Compressed Air Monitoring (B2.1.14)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)

3.3.2.1.15 Service Air

Materials

The materials of construction for the service air system component types are:

- Copper alloy
- Copper alloy (>15% Zn)
- Stainless steel
- Steel

Environment

The service air system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Condensation

Aging Effects Requiring Management

The following aging effects, associated with the service air system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the service air system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)

3.3.2.1.16 Primary & Secondary Plant Gas Supplies

Materials

The materials of construction for the primary & secondary plant gas supplies system component types are:

- Copper alloy
- Copper alloy (>15% Zn)
- Stainless steel
- Steel

Environment

The primary & secondary plant gas supplies system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Gas
- Steam
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the primary & secondary plant gas supplies system, require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the primary & secondary plant gas supplies system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.3.2.1.17 Penetration Electrical

Materials

The materials of construction for the penetration electrical system component types are:

- Copper alloy (>15% Zn)
- Stainless steel

Environment

The penetration electrical system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Gas

Aging Effects Requiring Management

The following aging effects, associated with the penetration electrical system, require management:

- Cracking
- Loss of material

Aging Management Programs

The following aging management programs manage the aging effects for the penetration electrical system component types:

- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- One-Time Inspection (B2.1.20)

3.3.2.1.18 Leakage Monitoring

Materials

The materials of construction for the leakage monitoring system component types are:

- Copper alloy
- Stainless steel

Environment

The leakage monitoring system component types are exposed to the following environments:

- Air – indoor uncontrolled

Aging Effects Requiring Management

The following aging effects, associated with the leakage monitoring system, require management:

- Cracking
- Loss of material

Aging Management Programs

The following aging management programs manage the aging effects for the leakage monitoring system component types:

- One-Time Inspection (B2.1.20)

3.3.2.1.19 Chemical & Volume Control

Materials

The materials of construction for the chemical & volume control system component types are:

- Copper alloy
- Elastomer
- Glass
- Gray cast iron
- Non-metallic thermal insulation
- Stainless steel
- Stainless steel with internal lining
- Steel
- Steel with internal lining

Environment

The chemical & volume control system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Closed–cycle cooling water
- Gas
- Lubricating oil
- Raw water
- Reactor coolant
- Soil
- Steam
- Treated borated water
- Treated borated water >60°C (>140°F)
- Treated water
- Underground

Aging Effects Requiring Management

The following aging effects, associated with the chemical & volume control system, require management:

- Cracking
- Cumulative fatigue damage
- Flow blockage
- Hardening or loss of strength
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduced thermal insulation resistance
- Reduction of heat transfer
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the chemical & volume control system component types:

- ASME Code Class 1 Small-Bore Piping (B2.1.22)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)
- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.27)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Open-Cycle Cooling Water System (B2.1.11)
- Water Chemistry (B2.1.2)

3.3.2.1.20 Boron Recovery

Materials

The materials of construction for the boron recovery system component types are:

- Copper alloy
- Stainless steel
- Steel

Environment

The boron recovery system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed–cycle cooling water
- Steam
- Treated borated water
- Treated borated water >60°C (>140°F)
- Treated water
- Treated water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects, associated with the boron recovery system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the boron recovery system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.3.2.1.21 Sampling System

Materials

The materials of construction for the sampling system system component types are:

- Copper alloy
- Copper alloy (>15% Zn)
- Glass
- Gray cast iron
- Polymer
- PVC
- Stainless steel
- Steel

Environment

The sampling system system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed–cycle cooling water
- Condensation
- Gas
- Raw water
- Reactor coolant
- Steam
- Treated borated water
- Treated borated water >60°C (>140°F)
- Treated water
- Treated water >60°C (>140°F)
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the sampling system system, require management:

- Cracking
- Cracking or blistering
- Cumulative fatigue damage
- Hardening or loss of strength
- Long-term loss of material
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the sampling system system component types:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)
- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.3.2.1.22 Incore Instrumentation

Materials

The materials of construction for the incore instrumentation system component types are:

- Stainless steel

Environment

The incore instrumentation system component types are exposed to the following environments:

- Air – indoor uncontrolled

Aging Effects Requiring Management

The following aging effects, associated with the incore instrumentation system, require management:

- Cracking
- Loss of material

Aging Management Programs

The following aging management programs manage the aging effects for the incore instrumentation system component types:

- One-Time Inspection (B2.1.20)

3.3.2.1.23 Decontamination

Materials

The materials of construction for the decontamination system component types are:

- Stainless steel
- Steel

Environment

The decontamination system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the decontamination system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the decontamination system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)

3.3.2.1.24 Drains - Aerated

Materials

The materials of construction for the drains - aerated system component types are:

- Copper alloy
- Elastomer
- Glass
- Gray cast iron
- PVC
- Stainless steel
- Steel

Environment

The drains - aerated system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Concrete
- Treated borated water
- Treated water
- Underground
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the drains - aerated system, require management:

- Cracking
- Cracking or blistering
- Flow blockage
- Hardening or loss of strength
- Long-term loss of material
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the drains - aerated system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.27)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.3.2.1.25 Drains - Building Services

Materials

The materials of construction for the drains - building services system component types are:

- Copper alloy
- Elastomer
- Fiberglass
- Gray cast iron
- Gray cast iron with internal coating
- Stainless steel
- Steel

Environment

The drains - building services system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Concrete
- Raw water
- Underground
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the drains - building services system, require management:

- Cracking
- Cracking, blistering, loss of material
- Flow blockage
- Hardening or loss of strength
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the drains - building services system component types:

- Bolting Integrity (B2.1.9)
- Buried and Underground Piping and Tanks (B2.1.27)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)

3.3.2.1.26 Drains - Gaseous

Materials

The materials of construction for the drains - gaseous system component types are:

- Stainless steel
- Steel

Environment

The drains - gaseous system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed–cycle cooling water
- Gas
- Treated borated water
- Treated borated water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects, associated with the drains - gaseous system, require management:

- Cracking
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following aging management programs manage the aging effects for the drains - gaseous system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.3.2.1.27 Gaseous Waste Disposal

Materials

The materials of construction for the gaseous waste disposal system component types are:

- Stainless steel
- Steel

Environment

The gaseous waste disposal system component types 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 gaseous waste disposal system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the gaseous waste disposal system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)

3.3.2.1.28 Liquid & Solid Waste (Radioactive)

Materials

The materials of construction for the liquid & solid waste (radioactive) system component types are:

- Copper alloy
- Copper alloy (>15% Zn)
- Nickel alloy
- Stainless steel
- Steel

Environment

The liquid & solid waste (radioactive) system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed–cycle cooling water
- Raw water
- Treated water
- Underground
- Waste water
- Waste water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects, associated with the liquid & solid waste (radioactive) system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the liquid & solid waste (radioactive) system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.27)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.3.2.1.29 Oil Separation

Materials

The materials of construction for the oil separation system component types are:

- Copper alloy
- Fiberglass
- Stainless steel
- Steel

Environment

The oil separation system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the oil separation system, require management:

- Cracking
- Cracking, blistering, loss of material
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the oil separation system component types:

- Bolting Integrity (B2.1.9)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)

3.3.2.1.30 Radioactive Waste

Materials

The materials of construction for the radioactive waste system component types are:

- Stainless steel
- Steel

Environment

The radioactive waste system component types 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 radioactive waste system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the radioactive waste system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.3.2.1.31 Sanitary Sewage

Materials

The materials of construction for the sanitary sewage system component types are:

- Gray cast iron
- Polymer
- PVC
- Stainless steel
- Steel

Environment

The sanitary sewage system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the sanitary sewage system, require management:

- Cracking
- Cracking or blistering
- Hardening or loss of strength
- Long-term loss of material
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the sanitary sewage system component types:

- Bolting Integrity (B2.1.9)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)

3.3.2.1.32 Vents - Gaseous

Materials

The materials of construction for the vents - gaseous system component types are:

- Stainless steel
- Steel

Environment

The vents - gaseous system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Gas
- Steam
- Underground

Aging Effects Requiring Management

The following aging effects, associated with the vents - gaseous system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the vents - gaseous system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.27)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.3.2.1.33 Containment Vacuum

Materials

The materials of construction for the containment vacuum system component types are:

- Copper alloy
- Copper alloy (>15% Zn)
- Glass
- Gray cast iron
- Stainless steel
- Steel

Environment

The containment vacuum system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed–cycle cooling water
- Steam
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the containment vacuum system, require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the containment vacuum system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.3.2.1.34 Chilled Water

Materials

The materials of construction for the chilled water system component types are:

- Copper alloy
- Copper alloy (>15% Zn)
- Elastomer
- Glass
- Gray cast iron
- Stainless steel
- Steel
- Steel with internal coating

Environment

The chilled water system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed–cycle cooling water
- Condensation
- Lubricating oil
- Raw water
- Steam
- Treated borated water
- Underground

Aging Effects Requiring Management

The following aging effects, associated with the chilled water system, require management:

- Cracking
- Cumulative fatigue damage
- Flow blockage
- Hardening or loss of strength
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the chilled water system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.27)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.3.2.1.35 Heating & Ventilation

Materials

The materials of construction for the heating & ventilation system component types are:

- Aluminum
- Copper alloy
- Copper alloy (>15% Zn)
- Elastomer
- Glass
- Gray cast iron
- Polymer
- Stainless steel
- Steel
- Steel with internal coating

Environment

The heating & ventilation system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Closed–cycle cooling water
- Condensation
- Gas
- Lubricating oil
- Raw water
- Steam
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the heating & ventilation system, require management:

- Cracking
- Cracking or blistering
- Cumulative fatigue damage
- Flow blockage
- Hardening or loss of strength
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduction of heat transfer
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the heating & ventilation system component types:

- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Open-Cycle Cooling Water System (B2.1.11)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.3.2.1.36 High Radiation Sampling

Materials

The materials of construction for the high radiation sampling system component types are:

- Glass
- Stainless steel
- Steel

Environment

The high radiation sampling system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed–cycle cooling water
- Treated borated water
- Treated borated water >60°C (>140°F)
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the high radiation sampling system, require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the high radiation sampling system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.3.2.1.37 Post-Accident Hydrogen Removal

Materials

The materials of construction for the post-accident hydrogen removal system component types are:

- Copper alloy (>15% Zn)
- Gray cast iron
- Stainless steel
- Steel

Environment

The post-accident hydrogen removal system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Gas

Aging Effects Requiring Management

The following aging effects, associated with the post-accident hydrogen removal system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the post-accident hydrogen removal system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)

3.3.2.1.38 Radiation Monitoring

Materials

The materials of construction for the radiation monitoring system component types are:

- Stainless steel
- Steel

Environment

The radiation monitoring system component types 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 radiation monitoring system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the radiation monitoring system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)

3.3.2.1.39 Alternate AC

Materials

The materials of construction for the alternate ac system component types are:

- Aluminum
- Copper alloy
- Copper alloy (>15% Zn)
- Elastomer
- Glass
- Gray cast iron
- Stainless steel
- Steel
- Steel with internal coating

Environment

The alternate ac system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air – outdoor
- Closed–cycle cooling water
- Closed–cycle cooling water >60°C (>140°F)
- Condensation
- Diesel exhaust
- Fuel oil
- Lubricating oil

Aging Effects Requiring Management

The following aging effects, associated with the alternate ac 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 aging management programs manage the aging effects for the alternate ac system component types:

- Bolting Integrity (B2.1.9)
- Closed Treated Water Systems (B2.1.12)
- Compressed Air Monitoring (B2.1.14)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Fuel Oil Chemistry (B2.1.18)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)

3.3.2.1.40 Emergency Diesel Generator System

Materials

The materials of construction for the emergency diesel generator system system component types are:

- Aluminum
- Copper alloy
- Copper alloy (>15% Zn)
- Elastomer
- Elastomer with stainless steel sheath
- Glass
- Gray cast iron
- Polymer
- Stainless steel
- Steel
- Steel with internal coating

Environment

The emergency diesel generator system system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air – outdoor
- Closed–cycle cooling water
- Closed–cycle cooling water >60°C (>140°F)
- Condensation
- Diesel exhaust
- Fuel oil
- Lubricating oil
- Soil
- Underground

Aging Effects Requiring Management

The following aging effects, associated with the emergency diesel generator system system, require management:

- Cracking
- Cracking or blistering
- 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 aging management programs manage the aging effects for the emergency diesel generator system system component types:

- Bolting Integrity (B2.1.9)
- Buried and Underground Piping and Tanks (B2.1.27)
- Closed Treated Water Systems (B2.1.12)
- Compressed Air Monitoring (B2.1.14)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Fuel Oil Chemistry (B2.1.18)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)

3.3.2.1.41 Security

Materials

The materials of construction for the security system component types are:

- Copper alloy
- Fiberglass
- Gray cast iron
- Polymer
- Steel

Environment

The security system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Condensation
- Diesel exhaust
- Fuel oil
- Soil
- Underground

Aging Effects Requiring Management

The following aging effects, associated with the security system, require management:

- Blistering
- Cracking
- Cracking or blistering
- Cracking, blistering, loss of material
- Cumulative fatigue damage
- Flow blockage
- Hardening or loss of strength
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the security system component types:

- Bolting Integrity (B2.1.9)
- Buried and Underground Piping and Tanks (B2.1.27)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Fuel Oil Chemistry (B2.1.18)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)

3.3.2.1.42 Fire Protection

Materials

The materials of construction for the fire protection system component types are:

- Aluminum
- Copper alloy
- Copper alloy (>15% Zn)
- Ductile iron
- Ductile iron with internal lining
- Elastomer
- Glass
- Gray cast iron
- Non-metallic thermal insulation
- Stainless steel
- Steel

Environment

The fire protection system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Concrete
- Fuel oil
- Gas
- Raw water
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the fire protection system, require management:

- Cracking
- Flow blockage
- Hardening
- Hardening or loss of strength
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of material or cracking
- Loss of preload
- Loss of strength
- Reduced thermal insulation resistance
- Shrinkage

Aging Management Programs

The following aging management programs manage the aging effects for the fire protection system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.27)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Fire Protection (B2.1.15)
- Fire Water System (B2.1.16)
- Fuel Oil Chemistry (B2.1.18)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)

3.3.2.1.43 Containment Access

Materials

The materials of construction for the containment access system component types are:

- Aluminum
- Copper alloy (>15% Zn)
- Stainless steel
- Steel

Environment

The containment access system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Lubricating oil

Aging Effects Requiring Management

The following aging effects, associated with the containment access system, require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the containment access system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)

3.3.2.1.44 Generator Breaker Cooling

Materials

The materials of construction for the generator breaker cooling system component types are:

- Polymer
- Stainless steel
- Steel

Environment

The generator breaker cooling system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Condensation
- Raw water
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the generator breaker cooling system, require management:

- Cracking
- Cracking or blistering
- Hardening or loss of strength
- Long-term loss of material
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the generator breaker cooling system component types:

- Bolting Integrity (B2.1.9)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.3.2.1.45 Water Treatment

Materials

The materials of construction for the water treatment system component types are:

- Copper alloy
- Elastomer
- Fiberglass
- Glass
- Gray cast iron
- Polymer
- PVC
- Stainless steel
- Steel

Environment

The water treatment system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Raw water
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the water treatment system, require management:

- Cracking
- Cracking or blistering
- Cracking, blistering, loss of material
- Hardening or loss of strength
- Long-term loss of material
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the water treatment system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.3.2.2 Further Evaluation of Aging Management as Recommended by NUREG-2192

NUREG-2192 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 evaluations are addressed in the following sections.

3.3.2.2.1 Cumulative Fatigue Damage

Evaluations involving time-dependent fatigue or cyclical loading parameters may be time-limited aging analyses (TLAAs), as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.3, “Metal Fatigue,” or Section 4.7, “Other Plant-Specific Time-Limited Aging Analyses,” of this SRP SLR. For plant-specific cumulative usage factor calculations that are based on stress-based input methods, the methods are to be appropriately defined and discussed in the applicable TLAAs.

[3.3.1-001] – Load cycles of NUREG-0612 plant cranes is a time-limited aging analysis (TLAA), as defined in 10 CFR 54.3. The evaluation of this TLAA is addressed in Section 4.7.1, Crane Load Cycle Limits.

[3.3.1-002] – Fatigue of Auxiliary Systems and Steam and Power Conversion Systems components is a TLAA, as defined in 10 CFR 54.3. The evaluation of this TLAA is addressed in Section 4.3.3, USAS (ANSI) B31.1 Allowable Stress Analyses.

3.3.2.2.2 Cracking Due to Stress Corrosion Cracking and Cyclic Loading

Cracking due to stress corrosion cracking (SCC) and cyclic loading could occur in stainless steel (SS) PWR nonregenerative heat exchanger tubing exposed to treated borated water greater than 60 °C (Celsius) [140 (°F) (Fahrenheit)] in the chemical and volume control system. The existing AMP for monitoring and control of primary water chemistry in PWRs (GALL SLR Report AMP XI.M2, “Water Chemistry”) manages the aging effects of cracking due to SCC. However, control of water chemistry does not preclude cracking due to SCC and cyclic loading. Therefore, the effectiveness of the water chemistry control program should be verified to ensure that cracking is not occurring. If a search of plant specific operating experience (OE) does not reveal that cracking has occurred in nonregenerative heat exchanger tubing, this aging effect can be considered to be adequately managed by GALL-SLR Report AMP XI.M2. However, if cracking has occurred in nonregenerative heat exchanger tubing, the GALL-SLR Report recommends that AMP XI.M21A, “Closed Treated Water Systems,” be evaluated for inclusion of augmented requirements to conduct temperature and radioactivity monitoring of the shell side water, and where component configuration permits, periodic eddy current testing of tubes.

Cracking due to stress corrosion cracking and cyclic loading could occur in stainless steel PWR nonregenerative heat exchanger tubing exposed to treated borated water greater than 60 °C (140 °F) in the chemical and volume control system.

[3.3.1-003] – A review of NAPS operating experience confirmed that cracking of nonregenerative heat exchanger tubing has not been identified at NAPS. Cracking of the nonregenerative heat exchanger tubes is managed by the Water Chemistry (B2.1.2) program.

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 atmospheric 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.

A review of NAPS operating experience identified cracking of stainless steel piping in a valve pit and in a pipe tunnel in which groundwater inleakage to the areas wetted the piping with contaminants that supported stress corrosion cracking. The external environment in these below-grade areas where groundwater inleakage may wet components is called "underground" in the SLRA. The operating experience review did not identify cracking of stainless steel components in other air environments (air-indoor uncontrolled, air-outdoor, or condensation). Cracking of stainless steel components in an underground environment will be managed by the Buried and Underground Piping and Tanks (B2.1.27) program. The absence of the aging effect in other air environments will be confirmed by the One-Time Inspection (B2.1.20) program.

[3.3.1-004] – Cracking of stainless steel components exposed to air – indoor uncontrolled, air – outdoor, or condensation is managed by the One-Time Inspection (B2.1.20) program.

[3.3.1-146] – Cracking of stainless steel underground components is managed by the Buried and Underground Piping and Tanks (B2.1.27) program.

[3.3.1-205] – Cracking of stainless steel components exposed to air – indoor uncontrolled or condensation is managed by the One-Time Inspection (B2.1.20) program.

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 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 coatings that have been demonstrated to be impermeable to aqueous solutions and atmospheric air that contain halides. If a barrier coating is credited for isolating a component from a potentially aggressive environment, then the barrier coating is evaluated to verify that it is impervious to the plant specific environment. 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 NAPS operating experience identified cracking of stainless steel piping in a valve pit and in a pipe tunnel in which groundwater inleakage to the areas wetted the piping with contaminants that supported stress corrosion cracking. Surface discoloration was also noted that may represent loss of material. The external environment in these below-grade areas where groundwater inleakage may wet components is called “underground” in the SLRA. Loss of material of stainless steel in underground environments requires aging management because the same contaminants that support cracking of stainless steel also support loss of material. The operating experience review did not identify loss of material due to pitting or crevice corrosion for stainless steel or nickel alloy piping, piping components, or tanks in other air environments (air-indoor uncontrolled, air-outdoor, or condensation). Loss of material for stainless steel components in an underground environment will be managed by the Buried and Underground Piping and Tanks (B2.1.27) program. The absence of the aging effect in other air environments will be confirmed by the One-Time Inspection (B2.1.20) program.

[3.3.1-006] – Loss of material of stainless steel or nickel alloy components exposed to air-indoor uncontrolled, air-outdoor, or condensation is managed by the One-Time Inspection (B2.1.20) program.

[3.3.1-222] – Loss of material of stainless steel tanks exposed to air-indoor uncontrolled is managed by the One-Time Inspection (B2.1.20) program.

[3.3.1-232] – Loss of material of stainless steel components exposed to condensation is managed by the One-Time Inspection (B2.1.20) program.

[3.3.1-241] – Loss of material of stainless steel heat exchanger components exposed to air-indoor uncontrolled is managed by the One-Time Inspection (B2.1.20) program.

[3.3.1-246] – Loss of material of underground stainless steel components is managed by the Buried and Underground Piping and Tanks (B2.1.27) program.

3.3.2.2.5 Quality Assurance for Aging Management of Nonsafety-Related Components

Quality Assurance provisions applicable to subsequent license renewal are discussed in Appendix B1.3, Quality Assurance Program and Administrative Controls.

3.3.2.2.6 Ongoing Review of Operating Experience

The operating experience process and acceptance criteria are described in Appendix B1.4, Operating Experience.

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.

[3.3.1-127] - The review of plant-specific operating experience has identified recurring internal corrosion (RIC) in steel and stainless steel piping and components exposed to raw water in the service water and bearing cooling systems, and in steel piping in the fire protection system. The programs noted below will manage RIC in the systems indicated.

A. Open-Cycle Cooling Water System (B2.1.11) program

As described below, the Open-Cycle Cooling Water System (B2.1.11) program will manage aspects of RIC in the service water system that are within the scope of the program. The Internal Coatings/Linings for In-scope Piping, Piping Components, Heat Exchangers and Tanks (B2.1.28) program will manage loss of material on the internal surfaces of service water system piping that has been lined or coated. In addition, the Appendix B operating experience section for the Open-Cycle Cooling Water System (B2.1.11) program identifies corrective actions that have been taken, and additional actions that are scheduled, to minimize the likelihood of piping and component degradation due to RIC. Future occurrences of RIC in piping and components within the scope of the Open-Cycle Cooling Water System (B2.1.11) program will be documented in accordance with the Corrective Action Program. The Open-Cycle Cooling Water System (B2.1.11) program and associated enhancements are described in Appendix B.

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:

Loss of Material in Uncoated Steel and Stainless Steel Piping:

Recurring internal corrosion has occurred in the service water system from 2009 to 2019 due to microbiologically-influenced corrosion (MIC) and pitting in uncoated steel and stainless-steel piping with specific corrective actions implemented for the spray array piping, charging pump cooler piping, and main control room chiller piping.

Spray array piping: In 2005 to 2009, the service water system spray array carbon steel piping was replaced as a corrective action for multiple leaks identified from 1998 to 2004. A subsequent design change was developed to provide for changing the drainpipe configuration by removing the previously installed 90-degree elbow and returning to the original straight down drain design which would limit the wear on system piping and reduce the suspended particulates in the water.

Charging pump cooler piping: To eliminate the piping leaks with the charging pump and speed increaser oil cooler supply and return lines a design change replaced MIC susceptible stainless-steel piping outside of the pump cubicles with ALX-6N. Since this pipe replacement project was completed, no additional leaks have occurred in those sections of ALX-6N pipe. To further mitigate potential future MIC related stainless steel pipe failures, design changes were developed to replace stainless steel pipe with ALX-6N inside the charging pump cubicles for the service water supply and return lines for the pump and speed increaser oil coolers. One pump's piping has been replaced and the remainder are scheduled.

Main control room chiller piping: Continued loss of material and leaks on the main control room chiller carbon steel service water lines has been identified and is being trended by Engineering using a periodic test. To supplement the normal UT data, a work order is scheduled to obtain UT data on additional Unit 1 and Unit 2 service water lines. This additional data will be used to evaluate the piping wall thickness and determine future corrective actions.

Periodic service water system piping inspections, spray array flow testing, and piping wall thickness measurements are performed to identify piping degradation prior to loss of system intended function. In addition to corrective actions associated with charging pump cooler piping replacements and trending of main control room chiller piping to address instances of RIC, Low Frequency Electromagnetic Technique (LFET) or similar technique will be used for screening 100 feet of piping during each refueling cycle to detect changes in the wall thickness of the pipe. LFET screening or a similar technique will also be performed on accessible piping during periodic inspections. Thinned areas found during the LFET scan are followed up with wall thickness examinations to ensure aging effects are managed and that wall thickness is within acceptable limits. In addition to the wall thickness examination, opportunistic visual inspections of the service water system will be performed whenever the service water system is opened for maintenance.

Loss of Material in Coated Steel Piping:

See the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program discussion in this further evaluation section for recurring internal corrosion details.

b) Basis for the adequacy of augmented or lack of augmented inspections:

Currently performed spray array flow testing and proposed service water system piping wall thickness measurements will provide sufficient data for trending service water system pipe wall conditions prior to loss of intended function. Inspection samples for the 100 feet of piping will be selected from piping not previously replaced or inspected and determined to be potentially susceptible to RIC based on prior piping replacements or inspection results that require trending. Identified degraded pipe due to corrosion has been evaluated and replaced when necessary prior to loss of intended function. The proposed wall thickness measurements and opportunistic inspections are sufficient to detect RIC.

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):

Parameters trended are pipe wall thickness measurements identified as a result of LFET results. When degraded conditions are identified, engineering evaluations are performed to determine the cause. If corrosion is identified, engineering evaluation will determine if additional inspections are required, the appropriate frequency of the inspection based on the projected corrosion rate, extent of condition for other areas in the system, and necessary repairs, if required.

d) How inspections of components that are not easily accessed (i.e., buried, underground) will be conducted:

Service water system piping discussed in this section is accessible for examination. See the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program discussion in this further evaluation section for inspections of buried and underground service water piping.

e) How leaks in any involved buried or underground components will be identified:

Service water system piping discussed in this section is accessible for examination. See the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program discussion in this further evaluation section for inspections of buried and underground service water piping.

B. Fire Water System (B2.1.16) program

As described below, the Fire Water System (B2.1.16) program will manage RIC in the fire protection system. In addition, the Appendix B operating experience section for the Fire Water System (B2.1.16) program identifies corrective actions have been taken, and additional actions that are scheduled, to minimize the likelihood of piping and component degradation due to RIC. Future occurrences of RIC in piping and components within the scope of the Fire Water System (B2.1.16) program will be documented in accordance with the Corrective Action Program. The Fire Water System (B2.1.16) program and associated enhancements are described in Appendix B.

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:

Periodic fire protection system piping flushes, flow testing and proposed piping thickness measurements will be performed to identify pipe degradation prior to loss of system intended function. In addition to recent piping replacements in the Turbine Building and the Auxiliary Building to address instances of RIC due to microbiologically-influenced corrosion, Low Frequency Electromagnetic Technique (LFET) or similar technique will be used for screening 100 feet of piping during each refueling cycle to detect changes in the wall thickness of the pipe. Thinned areas found during the LFET scan are followed up with wall thickness examinations to ensure aging effects are managed and that wall thickness is within acceptable limits. In addition to the wall thickness examination, opportunistic visual inspections of the fire protection system will be performed whenever the fire water system is opened for maintenance.

b) Basis for the adequacy of augmented or lack of augmented inspections:

Currently performed flow testing and proposed thickness measurements will provide sufficient data for trending fire water system pipe wall conditions prior to loss of intended function. Inspection samples for the 100 feet of piping will be selected from piping not previously replaced or inspected and determined to be potentially susceptible to RIC based on prior piping replacements or inspection results that require trending. Identified degraded pipe due to corrosion has been evaluated and replaced when necessary prior to loss of intended function. Other than proposed wall thickness measurements and opportunistic inspections, additional augmented inspections to detect RIC are not required.

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):

Parameters trended during piping flow tests include flow rates, pressure drops, calculated friction losses and/or signs of debris from corrosion. Parameters trended are pipe wall thickness measurements identified as a result of LFET results. When degraded conditions are identified, engineering evaluations are performed to determine the cause. If corrosion is identified, engineering evaluation will determine if additional inspections are required, the appropriate frequency of the inspection based on the projected corrosion rate, extent of condition for other areas in the system, and necessary repairs, if required.

d) How inspections of components that are not easily accessed (i.e., buried, underground) will be conducted:

Buried fire protection system piping is made of cast iron or ductile iron with a cementitious lining. In May 2013, a design change was completed to replace sections of cementitious lined cast iron piping with a higher pressure rated cementitious lined ductile iron due to internal pipe failures that were attributed to preexisting conditions in the cast iron pipe and not due to the failure of the lining. Materials analysis reports associated with the pipe failures stated the cementitious liner was tightly adhered to the pipe or in good contact with the existing pipe. Future inspections on underground fire main piping will be performed on an opportunistic basis when corrective maintenance work is performed on the fire water buried piping.

e) How leaks in any involved buried or underground components will be identified:

The water-based fire protection system is normally maintained at required operating pressure and is monitored such that loss of system pressure is detected and corrective actions initiated. A low pressure condition is alarmed in the main control room by the auto start of the electric motor driven fire pump, followed by the start of the diesel-driven fire pump if the low pressure condition continues to exist. The status of the fire pumps is indicated in the main control room and at the fire pump control panels in the pump house. Both fire pumps may be manually started from the main control room. The combination of continuous monitoring of the fire protection system header pressure and the associated alarm with operator actions are sufficient activities for the identification of leaks in the fire protection system buried components.

C. Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program

As described below, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program will manage RIC in portions of the bearing cooling system. In addition, the Appendix B operating experience section for the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program identifies corrective actions have been taken, and additional actions that are scheduled, to minimize the likelihood of piping and component degradation due to RIC. Future occurrences of RIC in piping and components within the scope of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program will be documented in accordance with the Corrective Action Program. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program and associated enhancements are described in Appendix B.

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:

The existing Unit 1 and Unit 2 bearing cooling system wall thickness examinations will be enhanced to require performance of a minimum of 10 piping wall thickness measurements with a frequency not to exceed two refueling cycle intervals. Locations in a 2016 sample population with a wall thickness of less than 50% will be selected and augmented as necessary considering prior inspection results, extent of degradation, rate of degradation, and timing of the next inspection.

b) Basis for the adequacy of augmented or lack of augmented inspections:

Bearing cooling system piping wall thickness measurements were performed and evaluated to identify when corrective actions or pipe replacement were required prior to a loss of intended function. An Engineering evaluation of 52 Unit 1 locations examined in 2016 indicated that four runs of pipe (12 inches and 24 inches) exceeded acceptable corrosion rates. Of these, two were scheduled for replacement within 10 years and the remaining two did not require replacement for more than 20 years. An Engineering evaluation of 48 Unit 2 locations examined in 2016 indicated that three runs of pipe (12 inches and 16 inches) exceeded acceptable corrosion rates. However, none of the Unit 2 piping required replacement within the next 30 years. Piping wall thickness measurements for vulnerable bearing cooling system piping are collected at two refueling cycle intervals.

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):

Bearing cooling system piping wall thickness measurement examination results are trended at vulnerable locations. Vulnerable locations are identified as locations less than 50% wall thickness or locations approaching minimum wall thickness. Degradation of wall thickness is projected to the next inspection using corrosion rates based on wall thickness examination results.

d) How inspections of components that are not easily accessed (i.e., buried, underground) will be conducted:

The bearing cooling system piping within the scope of subsequent license renewal is not located in buried or underground environments.

e) How leaks in any involved buried or underground components will be identified:

The bearing cooling system piping within the scope of subsequent license renewal is not located in buried or underground environments.

D. Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program

As described below, the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program will manage RIC in the service water system. In addition, the Appendix B operating experience section for the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program identifies corrective actions have been taken, and additional actions that are scheduled, to minimize the likelihood of piping and component degradation due to RIC. Future occurrences of RIC in piping and components within the scope of the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program will be documented in accordance with the Corrective Action Program. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program and associated enhancements are described in Appendix B.

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:

For epoxy-coated service water system piping sections, inspection is performed of approximately 10 percent of the service water system internal coatings each refueling cycle, thereby 100 percent of all the service water system piping is inspected every 15 years.

b) Basis for the adequacy of augmented or lack of augmented inspections:

For piping sections, inspection of approximately 10 percent of the service water system internal coatings each refueling cycle provides an adequate sample size for detecting aging effects prior to loss of intended function. As a result of the inspection protocol with a 10 percent sample population, 100 percent of the service water internal coatings is inspected every 15 years.

During the last five years (2015-2019), there has been no Unit 2 piping minimum wall thickness failures as a result of pitting due to loss of coating integrity of in-scope coated service water piping. During the last five years (2015-2019), there have only been two Unit 1 piping minimum wall thickness failures on the same header as a result of pitting due to loss of coating integrity of in-scope coated service water piping.

Augmented inspections are not required. When degradation is observed, the need for increased inspections will be evaluated as part of the program's corrective actions.

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):

The condition of the internal coatings of the service water system will be assessed during scheduled inspections, and any degraded conditions recorded in the Corrective Action Program. The need for increased inspections will be evaluated as part of the corrective actions, considering past inspection results, extent of degradation, and rate of degradation.

d) How inspections of components that are not easily accessed (i.e., buried, underground) will be conducted:

Internal access is available to allow inspection of internal surfaces of portions of the service water system piping that are buried.

e) How leaks in any involved buried or underground components will be identified:

Internal access is available to allow inspection of internal surfaces of portions of the service water system piping that are buried. Internal coating degradation and substrate metal degradation are identified with visual inspections.

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. If a barrier coating is credited for isolating an aluminum alloy from a potentially aggressive environment, then the barrier coating is evaluated to verify that it is impervious to the plant-specific environment. 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.

Cracking due to stress corrosion cracking is an aging effect requiring management for aluminum alloy components exposed to air or condensation in the Auxiliary Systems.

[3.3.1-189] – This item evaluates cracking of aluminum components exposed to air – indoor uncontrolled, condensation, or raw water. There are no sources of halides associated with indoor air at NAPS, or associated with wetted surfaces caused by condensation of indoor air. While small amounts of halides may be present in raw water from environmental sources, the operating experience at NAPS indicates that the concentration is not sufficient to contribute to aging that causes a loss of function for aluminum components. The following component types in the identified systems are exposed to air – indoor uncontrolled, condensation or raw water and are constructed of aluminum alloys that are susceptible to SCC, or are assumed to be susceptible to SCC because the specific series of the aluminum alloy is unknown.

Alternate AC system valve bodies in the alternate AC diesel start air subsystem. These valves are exposed to a halide free air - indoor uncontrolled environment in the Alternate AC Building, are not encapsulated in materials containing halides, and are not exposed to known sources of moisture or halides.

Containment access system pump casing (hydraulic – electric). These pumps are exposed to a halide free air - indoor uncontrolled environment in the Containment Building, are not encapsulated in materials containing halides, and are not exposed to known sources of moisture or halides.

Circulating water system tank (ball collector cover). These tanks are exposed to a halide free air - indoor uncontrolled environment in the Turbine Building, are not encapsulated in materials containing halides, and are not exposed to known sources of moisture or halides. The internal surfaces of the tanks are exposed to raw water with no known sources of halides.

Emergency diesel generator filter housings in the diesel air start subsystem. These air dryer prefilters are exposed to a halide free air - indoor uncontrolled external environment and to a condensation internal environment (due to condensation of compressed indoor air) in the Emergency Diesel Generator rooms and Service Building, are not encapsulated in materials containing halides, and are not exposed to known sources of halides.

Fire protection system odorizers. These components are exposed to a halide free air - indoor uncontrolled environment both internally and externally in the Auxiliary Building, Emergency Diesel Generator rooms, Service Building and Turbine Building. They are not encapsulated in materials containing halides, and are not exposed to known sources of halides.

Helium vacuum drying system fittings (KF piping clamps). These piping clamps are exposed to a halide free air - indoor uncontrolled environment in the Fuel Building, are not encapsulated in materials containing halides, and are not exposed to known sources of moisture or halides.

Instrument air system sight glass bodies. These components are exposed to a halide free air - indoor uncontrolled environment in the Auxiliary Building, are not encapsulated in materials containing halides, and are not exposed to known sources of halides.

A review of NAPS operating experience did not identify a history of cracking of aluminum alloy components. The absence of the aging effect will be confirmed by the One-Time Inspection (B2.1.20) program.

[3.3.1-254] – This item evaluates cracking of aluminum heat exchanger components exposed to air or condensation. There are no sources of halides associated with indoor air at NAPS, or associated with wetted surfaces caused by condensation of indoor air. While small amounts of halides may be present in outside air from environmental sources, the operating experience at NAPS indicates that the concentration is not sufficient to contribute to aging that causes a loss of function for aluminum components. The following component types in the identified systems are exposed to air – indoor uncontrolled, air – outdoor, or condensation and are constructed of aluminum alloys that are susceptible to SCC, or are assumed to be susceptible to SCC because the specific series of the aluminum alloy is unknown.

Alternate AC system heat exchanger fins in the alternate AC diesel cooling water radiators. These heat exchanger fins are exposed to a halide free air - indoor uncontrolled environment in the Alternate AC Building, are not encapsulated in materials containing halides, and are not exposed to known sources of moisture or halides.

Alternate AC system heat exchanger fins in the alternate AC diesel fuel oil radiators. These heat exchanger fins are exposed to an air - outdoor environment at the Alternate AC Building, are not encapsulated in materials containing halides, and are not exposed to known sources of halides.

Heating and ventilation system air handling unit fins. These air handling unit fins are exposed to a halide free condensation environment internal to the air handling units (caused by condensation of indoor air on cold surfaces) in the Service Building, are not encapsulated in materials containing halides, and are not exposed to known sources of halides.

A review of NAPS operating experience did not identify a history of cracking of aluminum alloy components. Cracking of aluminum heat exchanger components exposed to air – indoor uncontrolled, air – outdoor, or condensation is managed by the One-Time Inspection (B2.1.20) program.

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.

Loss of material due to general, crevice, or pitting corrosion can occur in steel components exposed to concrete.

[3.3.1-112] – Loss of material of gray cast iron and steel piping components with an external environment of concrete that do not exit the concrete into soil is not an aging effect requiring management. Piping components that do not exit the concrete into soil are not potentially exposed to groundwater. The concrete in areas containing these components conforms to ACI 318. Review of NAPS operating experience did not identify degradation of concrete around embedded components that could lead to penetration of water.

Loss of material can occur for steel piping components with an external environment of concrete that are potentially exposed to groundwater. Embedded piping that exits concrete into soil is potentially exposed to groundwater. Loss of material for steel components with an external environment of concrete that exit the concrete into soil is managed by the Buried and Underground Piping and Tanks (B2.1.27) program as identified in row [3.3.1-109]

[3.3.1-202] – Loss of material and cracking of stainless steel components exposed to concrete is not an aging effect for components that are not potentially exposed to groundwater. Stainless steel piping components exposed to concrete in the drains-aerated, helium vacuum drying, refueling purification, and fuel pit cooling systems are embedded within interior concrete structures and are not potentially exposed to groundwater.

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 generally 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 generally 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 atmospheric air that contain halides. If a barrier coating is credited for isolating an aluminum alloy from a potentially aggressive environment, then the barrier coating is evaluated to verify that it is impervious to the plant specific environment. 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 NAPS operating experience did not identify a history of loss of material of in-scope aluminum alloy components. The absence of the aging effect will be confirmed by the One-Time Inspection (B2.1.20) program.

[3.3.1-234] – Loss of material of aluminum components exposed to air – indoor uncontrolled or condensation is managed by the One-Time Inspection (B2.1.20) program.

[3.3.1-242] – Loss of material of aluminum heat exchanger components exposed to air – indoor uncontrolled, air – outdoor, or condensation is managed by the One-Time Inspection (B2.1.20) program.

[3.3.1-247] – Loss of material of aluminum components exposed to raw water is managed by the One-Time Inspection (B2.1.20) program.

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Results Tables: Auxiliary Systems

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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. Cumulative fatigue damage of steel crane rails and retaining clips, girders, beams, and plates exposed to air - indoor uncontrolled is a TLAA. See further evaluation in Section 3.3.2.2.1.
3.3.1-002	Stainless steel, steel heat exchanger components and tubes, piping, piping components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, SRP-SLR Section 4.3 Metal Fatigue	Yes (SRP-SLR Section 3.3.2.2.1)	Consistent with NUREG-2191. Cumulative fatigue damage of stainless steel and steel components exposed to diesel exhaust, steam, treated borated water >60°C (>140°F), treated water, or treated water >60°C (>140°F) is a TLAA. In addition to Auxiliary Systems, components in Steam and Power Conversion System (auxiliary boilers, condensate, extraction steam, feedwater, main steam, and steam drains) are aligned to this item. See further evaluation 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. See further evaluation 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 applicable. A review of NAPS operating experience confirmed that cracking of nonregenerative heat exchanger tubing has not been identified at NAPS. Cracking of the nonregenerative heat exchanger tubes is managed by the Water Chemistry (B2.1.2) program as addressed in row 3.3.1-003. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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. Cracking of stainless steel components exposed to air - indoor uncontrolled, air - outdoor, or condensation is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.3.2.2.3.
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. Loss of material of stainless steel and nickel alloy components exposed to air - indoor uncontrolled, air - outdoor, or condensation is managed by the One-Time Inspection (B2.1.20) program. See further evaluation 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, Subsections IWB, IWC, and IWD	No	Consistent with NUREG-2191.
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, Subsections IWB, IWC, and IWD	No	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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.
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. NAPS has no in-scope high-strength steel closure bolting exposed to air, soil, or underground in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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.
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.
3.3.1-016	Stainless steel piping, piping components outboard the second containment isolation valves with a diameter ,â•4 inches nominal pipe size exposed to treated water >93°C (>200°F)	Cracking due to SCC, IGSCC	AMP XI.M2, Water Chemistry, and AMP XI.M25, BWR Reactor Water Cleanup System	No	Not applicable - BWR only.
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.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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 applicable. Cracking of stainless steel components exposed to treated borated water >60°C (>140°F) is addressed in rows 3.3.1-028 and 3.3.1-124. The associated NUREG-2191 aging items are not used.
3.3.1-019	Stainless steel regenerative heat exchanger 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 - BWR only.
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.
3.3.1-021	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 applicable - BWR only.
3.3.1-022	Copper alloy piping, piping 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	Not applicable - BWR only.
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. NAPS has no in-scope aluminum piping, piping components exposed to treated water or treated borated water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-026	Steel (with stainless steel cladding) piping, piping components exposed to treated water	Loss of material due to general (only after cladding degradation), pitting, crevice corrosion, MIC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable - BWR only.
3.3.1-027	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	Not applicable - BWR only.
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.
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. NAPS has no in-scope concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to raw water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-030a	Fiberglass, HDPE piping, piping components exposed to raw water	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture; flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System	No	Not applicable. Cracking, blistering, loss of material and flow blockage of fiberglass components exposed to raw water is addressed in row 3.3.1-175. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-034	Nickel alloy, copper alloy piping, piping components exposed to raw water	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System	No	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Open-Cycle Cooling Water System (B2.1.11) program implementation.
3.3.1-037	Steel piping, piping components exposed to raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System	No	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Open-Cycle Cooling Water System (B2.1.11) program implementation.
3.3.1-038	Copper alloy, steel heat exchanger components exposed to raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System	No	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Open-Cycle Cooling Water System (B2.1.11) program implementation.
3.3.1-040	Stainless steel piping, piping components exposed to raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System	No	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Open-Cycle Cooling Water System (B2.1.11) program implementation.
3.3.1-042	Copper alloy, titanium, stainless steel heat exchanger tubes exposed to raw water, raw water (potable), treated water	Cracking due to SCC (titanium only), reduction of heat transfer due to fouling	AMP XI.M20, Open-Cycle Cooling Water System, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191 with exceptions. Cracking (titanium only) and reduction of heat transfer of copper alloy, titanium, stainless steel heat exchanger tubes exposed to raw water is managed by the Open-Cycle Cooling Water System (B2.1.11) program. Exceptions apply to the NUREG-2191 recommendations for Open-Cycle Cooling Water System (B2.1.11) program implementation.
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	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-044	Stainless steel; steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, Closed Treated Water Systems	No	Not applicable. NAPS has no in-scope stainless steel or steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water >60°C (>140°F) in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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.
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.
3.3.1-047	Stainless steel; steel with stainless steel cladding heat exchanger 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 - BWR only.
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	Consistent with NUREG-2191.
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.
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.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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. NAPS has no in-scope boraflex spent fuel storage racks: neutron-absorbing sheets (PWR) or spent fuel storage racks exposed to treated borated water or treated water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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.
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	Consistent with NUREG-2191.
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. Only components in Structures and Component Supports (miscellaneous structural commodities) are aligned to this item.
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.
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. Only components in Structures and Component Supports (Auxiliary Building, Service Building, Turbine Building, Administration Building, and miscellaneous structural commodities) are aligned to this item.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-060	Reinforced concrete structural fire barriers: walls, ceilings and floors exposed to air	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, or scaling	AMP XI.M26, Fire Protection, and AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191 with a different program for some components. The ASME Section XI, Subsection IWL (B2.1.30) program manages cracking and loss of material for reinforced concrete in the Containment Structure (Containment). Only components in Containment Structure (Containment) and Structures and Component Supports (Auxiliary Building, Auxiliary Feedwater Pump House, Fuel Oil Pump House, Main Steam Valve House, Quench Spray Pump House, Service Building, and Turbine Building) are aligned to this item.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B2.1.16) program implementation.
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 with exceptions and a different aging management program for some components. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B2.1.16) program implementation. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program manages loss of material for steel components exposed to treated water that is not managed by the Water Chemistry program (i.e., chemical addition components) in the service water system.
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. NAPS has no in-scope aluminum piping, piping components exposed to raw water, treated water, or raw water (potable) in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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 with exceptions and a different aging management program for some components. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B2.1.16) program implementation. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program manages loss of material of stainless steel components exposed to treated water that is not managed by the Water Chemistry program (i.e., chemical addition components) in the service water system.
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 exceptions. Exceptions apply to the NUREG-2191 recommendations for Fuel Oil Chemistry (B2.1.18) program implementation. In addition to Auxiliary Systems, components in Steam and Power Conversion System (auxiliary boilers) are aligned to this item.
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 exceptions. Exceptions apply to the NUREG-2191 recommendations for Fuel Oil Chemistry (B2.1.18) program implementation. In addition to Auxiliary Systems, components in Steam and Power Conversion System (auxiliary boilers system) are aligned to this item.
3.3.1-071	Stainless steel, aluminum piping, piping components exposed to fuel oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M30, Fuel Oil Chemistry, and AMP XI.M32, One-Time Inspection, or AMP XI.M30, Fuel Oil Chemistry	No	Consistent with NUREG-2191, with exceptions. Exceptions apply to the NUREG-2191 recommendations for Fuel Oil Chemistry (B2.1.18) program implementation. In addition to Auxiliary Systems, components in Steam and Power Conversion System (auxiliary boilers system) are aligned to this item.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-072	Gray cast iron, ductile iron, copper alloy (>15% Zn or >8% Al) piping, piping components, heat exchanger components exposed to treated water, closed-cycle cooling water, soil, raw water, raw water (potable), waste water	Loss of material due to selective leaching	AMP XI.M33, Selective Leaching	No	Consistent with NUREG-2191. In addition to Auxiliary Systems, components in Structures and Component Supports (Flood Protection Dike) and Steam and Power Conversion System (lubricating oil) are aligned to this item.
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. NAPS has no in-scope concrete, concrete cylinder piping, reinforced concrete, asbestos cement, or cementitious piping, piping components exposed to air – outdoor in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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 with a different program assigned for some components. In addition to Auxiliary Systems, components in Structures and Component Supports (Flood Protection Dike) are aligned to this item. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program will manage loss of material for the internal surface of the gray cast iron Structures and Component Supports (Flood Protection Dike) valve body exposed to air - outdoor, and the Structures Monitoring (B2.1.34) program will manage loss of material for the external surface of the gray cast iron Structures and Component Supports (Flood Protection Dike) valve body exposed to air - outdoor.
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.
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.
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.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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. In addition to Auxiliary Systems, components in Steam and Power Conversion System (condensate, feedwater) are aligned to this item.
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.
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. Loss of material of steel piping, piping components exposed to condensation (internal) is addressed in row 3.3.1-055. The associated NUREG-2191 aging items are not used.
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. Loss of material of steel components exposed to condensation (internal) is addressed in row 3.3.1-055. The associated NUREG-2191 aging items are not used.
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. In addition to Auxiliary Systems, components in Steam and Power Conversion System (auxiliary boilers, condensate polishing, and lubricating oil) are aligned to this item.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-093	Copper alloy piping, piping components exposed to raw water (potable)	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191.
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. Loss of material of stainless steel components exposed to air or condensation is addressed in row 3.3.1-006. The associated NUREG-2191 aging items are not used.
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. Cracking of stainless steel components exposed to air or condensation is addressed in row 3.3.1-004 and 3.3.1-205. The associated NUREG-2191 aging items are not used.
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 with a different program for some components. In addition to Auxiliary Systems, components in Reactor Vessel, Internals, And Reactor Coolant System (reactor coolant), Engineered Safety Features (recirculation spray, safety injection), and Steam and Power Conversion System (condensate polishing, lubricating oil) are aligned to this item. The External Surfaces Monitoring of Mechanical Components (B2.1.23) program will manage loss of material of the external surfaces of copper alloy sump pump casings in the drains - building services system.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-096	Elastomer piping, piping components, seals exposed to air, raw water, raw water (potable), treated water, waste water	Loss of material due to wear; flow blockage due to fouling (raw water, waste water only)	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191. In addition to Auxiliary Systems, components in Steam and Power Conversion System (condensate) are aligned to this item.
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.
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	Consistent with NUREG-2191.
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.
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.
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.
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.
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. NAPS has no in-scope aluminum heat exchanger tubes exposed to lubricating oil in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-102	Boral®, boron steel, and other materials (excluding Boraflex) spent fuel storage racks: neutron-absorbing sheets (PWR), spent fuel storage racks: neutron-absorbing sheets (BWR) exposed to treated borated water, treated water	Reduction of neutron-absorbing capacity; change in dimensions and loss of material due to effects of SFP environment	AMP XI.M40, Monitoring of Neutron-Absorbing Materials other than Boraflex	No	Not applicable. NAPS has no in-scope Boral®; boron steel, and other materials (excluding Boraflex) in spent fuel storage racks or neutron-absorbing sheets in spent fuel storage racks exposed to treated borated water or treated water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope concrete, concrete cylinder piping, reinforced concrete, asbestos cement, or cementitious piping, piping components exposed to soil, or concrete in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-104	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	Consistent with NUREG-2191.
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.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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.
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. In addition to Auxiliary Systems, components in Structures and Component Supports (Flood Protection Dike) are aligned to this item.
3.3.1-110	Stainless steel, nickel alloy piping, piping components greater than or equal to 4 NPS exposed to treated water >93°C (>200°F)	Cracking due to SCC, IGSCC	AMP XI.M7, BWR Stress Corrosion Cracking, and AMP XI.M2, Water Chemistry	No	Not applicable - BWR only.
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	Not applicable. Loss of material of steel structural steel exposed to air – indoor uncontrolled is addressed in rows 3.5.1-077, 3.5.1-083, 3.5.1-091, and 3.5.1-092. The associated NUREG-2191 aging items are not used.
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. See further evaluation in Section 3.3.2.2.9.
3.3.1-113	Aluminum piping, piping components exposed to gas	None	None	No	Not applicable. NAPS has no in-scope aluminum piping, piping components exposed to gas in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-114	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-115	Copper alloy, copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage	None	None	No	Not applicable. The air with borated water leakage environment was not applied to copper alloy in the Auxiliary Systems because the aging evaluation is equivalent to that for copper alloy in air - indoor uncontrolled, which is addressed by item 3.3.1-114. NAPS does not have copper alloy (>8% Al) in the Auxiliary Systems. 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	Not applicable. NAPS did not use “galvanized steel” as a material name. Aging of steel piping, piping components exposed to air-indoor uncontrolled is addressed in rows 3.3.1-058, 3.3.1-078, 3.3.1-131, 3.3.1-136, and 3.3.1-249. The associated NUREG-2191 aging items are not used.
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.
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. In addition to Auxiliary Systems, components in Reactor Vessel, Internals, And Reactor Coolant System (reactor coolant) and Steam and Power Conversion System (lubricating oil) are aligned to this item.
3.3.1-120	Stainless steel piping, piping components exposed to air with borated water leakage, gas	None	None	No	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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.
3.3.1-122	Titanium heat exchanger components, piping, piping components exposed to air – indoor uncontrolled, air – outdoor	None	None	No	Not applicable. NAPS has no in-scope titanium heat exchanger components or piping, piping components exposed to air – indoor uncontrolled or air – outdoor in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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	Consistent with NUREG-2191 with exceptions. Cracking and flow blockage of steel with titanium (ASTM Grade 1) cladding heat exchanger channels exposed to raw water is managed by the Open-Cycle Cooling Water System (B2.1.11) program. Exceptions apply to the NUREG-2191 recommendations for Open-Cycle Cooling Water System (B2.1.11) program implementation.
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.
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.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-126	Metallic piping, piping components exposed to treated water, treated borated water, raw water	Wall thinning due to erosion	AMP XI.M17, Flow-Accelerated Corrosion	No	Consistent with NUREG-2191.
3.3.1-127	Metallic piping, piping components, tanks exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, waste water	Loss of material due to recurring internal corrosion	AMP XI.M20, Open-Cycle Cooling Water System, AMP XI.M27, Fire Water System, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Yes (SRP-SLR Section 3.3.2.2.7)	Consistent with NUREG-2191 with exceptions and with a different program for some components. Loss of material of metallic components exposed to raw water is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program, the Open-Cycle Cooling Water System (B2.1.11) program, the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program, and the Fire Water System (B2.1.16) program. Exceptions apply to the NUREG-2191 recommendations for Open-Cycle Cooling Water System (B2.1.11) program and Fire Water System (B2.1.16) program implementation. See further evaluation 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	Not applicable. NAPS has no in-scope steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil, concrete, air, condensation, raw water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B2.1.16) program implementation.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B2.1.16) program implementation.
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 with a different program for some components. Cracking of copper alloy (>15% Zn) components exposed externally to air – indoor uncontrolled, air – outdoor, or condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program. Cracking of copper alloy (>15% Zn) hose rack piping components exposed internally to air - indoor uncontrolled in the fire protection system is managed by the Fire Water System (B2.1.16) program.
3.3.1-133	HDPE underground piping, piping components	Cracking, blistering	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. NAPS has no in-s.cope HDPE underground piping, piping components in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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.
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. In addition to Auxiliary Systems, components in Engineered Safety Features (recirculation spray and safety injection) are aligned to this item.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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 with exceptions and a different aging management program for some components. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B2.1.16) program. In addition to Auxiliary Systems, components in Structures and Component Supports (Flood Protection Dike) are aligned to this item. The Structures Monitoring (B2.1.34) program and the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program manage loss of material of steel and gray cast iron components exposed to raw water in Structures and Component Supports (Flood Protection Dike).
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	Not applicable. NAPS has no in-scope steel, stainless steel, or aluminum tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to treated water, raw water, or waste water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-138	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, treated borated water, fuel oil, lubricating oil, waste water	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage; loss of material or cracking for cementitious coatings/linings	AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	No	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program implementation. In addition to Auxiliary Systems, components in Structures and Component Supports (Flood Protection Dike) are aligned to this item.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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	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	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program implementation.
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	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program implementation.
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.
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.
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. In addition to Auxiliary Systems, components in Engineered Safety Features (recirculation spray, safety injection) are aligned to this item.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-146	Stainless steel underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.M41, Buried and Underground Piping and Tanks, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.3)	Consistent with NUREG-2191. Cracking of stainless steel underground components is managed by the One-Time Inspection (B2.1.20) program. See further evaluation 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. NAPS has no in-scope nickel alloy, nickel alloy cladding piping, piping components exposed to closed-cycle cooling water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope fiberglass piping, piping components, or ducting, ducting components exposed to air – outdoor in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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.
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.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-155	Stainless steel piping, piping components, and tanks exposed to waste water >60°C (>140°F)	Cracking due to SCC	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191.
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 applicable. Loss of material of steel piping, piping components and heat exchanger components exposed to air – outdoor is addressed in row 3.3.1-078. The associated NUREG-2191 aging items are not used.
3.3.1-158	Nickel alloy piping, piping components heat exchanger components (for components not covered by NRC GL 89-13) exposed to raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. NAPS has no in-scope nickel alloy piping, piping components or heat exchanger components (for components not covered by NRC GL 89-13) exposed to raw water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-159	Fiberglass piping, piping components, ducting, ducting components exposed to air	Loss of material due to wear	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. NAPS has no in-scope fiberglass piping, piping components or ducting, ducting components exposed to air (internal) in the Auxiliary Systems. Loss of material of fiberglass components exposed to air - indoor uncontrolled (external) is addressed in row 3.3.1-082. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-160	Copper alloy (>15% Zn or >8% Al) piping, piping components, heat exchanger components exposed to closed-cycle cooling water, raw water, waste water	Cracking due to SCC	AMP XI.M20, Open-Cycle Cooling Water System, AMP XI.M21A, Closed Treated Water Systems, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191 with exceptions and a different program for some components. Cracking of copper alloy (>15% Zn) components exposed to waste water is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. Cracking of copper alloy (>15% Zn) components exposed to raw water in the domestic water system is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. Cracking of copper alloy (>15% Zn) components exposed to raw water in the fire protection system is managed by the Fire Water System (B2.1.16) program. Exceptions apply to the NUREG-2191 recommendations for Fire Water System (B2.1.16) program. In addition to Auxiliary Systems, components in Steam and Power Conversion System (lubricating oil) are aligned to this item. Cracking of copper alloy (>15% Zn or >8% Al) components requires the presence of ammonia or ammonium compounds. These contaminants are not present in closed-cycle cooling water chemistries at NAPS.
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	Consistent with NUREG-2191.
3.3.1-166	Copper alloy piping, piping components exposed to concrete	None	None	No	Not applicable. NAPS has no in-scope copper alloy piping, piping components exposed to concrete in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-167	Zinc piping components exposed to air – indoor controlled, air – indoor uncontrolled	None	None	No	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-169	Steel, copper alloy piping, piping components exposed to steam	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191. In addition to Auxiliary Systems, components in Steam and Power Conversion System (auxiliary boilers system) are aligned to this item.
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	Consistent with NUREG-2191.
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. NAPS has no in-scope PVC piping, piping components exposed to air-outdoor in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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.
3.3.1-176	Fiberglass piping, piping components, tanks exposed to raw water environment (for components not covered by NRC GL 89-13), raw water (potable), treated water, waste water	Loss of material due to wear; flow blockage due to fouling (raw water, waste water only)	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. Loss of material of fiberglass piping, piping components exposed to raw water environment (for components not covered by NRC GL 89-13) or waste water is addressed in item 3.3.1-175. The associated NUREG-2191 aging items are not used.
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	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-178	Fiberglass piping and piping components exposed to concrete	None	None	No	Not applicable. NAPS has no in-scope fiberglass piping and piping components exposed to concrete in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-179	Masonry walls: structural fire barriers exposed to air	Cracking due to restraint shrinkage, creep, aggressive environment; loss of material (spalling, scaling) and cracking due to freeze-thaw	AMP XI.M26, Fire Protection, and AMP XI.S5, Masonry Walls	No	Consistent with NUREG-2191. Only components in Structures and Component Supports (Auxiliary Building, Service Building, Turbine Building, and Administration Building) are aligned to this item.
3.3.1-181	Titanium piping, piping components exposed to condensation	None	None	No	Not applicable. NAPS has no in-scope titanium piping, piping components exposed to condensation in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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	Consistent with NUREG-2191.
3.3.1-184	PVC piping, piping components, tanks exposed to concrete	None	None	No	Not applicable. NAPS has no in-scope PVC piping, piping components or tanks exposed to concrete in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), or treated water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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. NAPS has no in-scope aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation, soil, concrete, raw water, or waste water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. Cracking of aluminum components exposed to air - indoor uncontrolled, condensation, and raw water is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.3.2.2.8.
3.3.1-192	Aluminum underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.M41, Buried and Underground Piping and Tanks, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.8)	Not applicable. NAPS has no in-scope aluminum underground piping, piping components or tanks in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. In addition to Auxiliary Systems, components in Steam and Power Conversion System (auxiliary boilers, condensate polishing, and lubricating oil systems) are aligned to this item.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-194	PVC piping, piping components, and tanks exposed to soil	Loss of material due to wear	AMP XI.M41, Buried and Underground Piping and Tanks	No	Not applicable. NAPS has no in-scope PVC piping, piping components, or tanks exposed to soil in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope concrete, concrete cylinder piping, reinforced concrete, asbestos cement, or cementitious piping, piping components exposed to raw water, treated water, or raw water (potable) in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope HDPE piping, piping components exposed to raw water, treated water, or raw water (potable) in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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 applicable. Loss of material of 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 is addressed in row 3.3.1-078. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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 applicable. Loss of material of metallic fire water system components with only a leakage boundary (spatial) intended function exposed to a raw water internal environment is addressed in row 3.3.1-064. The associated NUREG-2191 aging items are not used.
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.
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. See further evaluation in Section 3.3.2.2.9.
3.3.1-203	Stainless steel; steel with stainless steel cladding, nickel alloy piping, piping components, heat exchanger components, tanks exposed to treated water, sodium pentaborate solution	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Not applicable - BWR only.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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. Cracking of stainless steel components exposed to air - indoor uncontrolled or condensation is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.3.2.2.3.
3.3.1-207	Stainless steel, copper alloy, titanium heat exchanger tubes exposed to raw water (for components not covered by NRC GL 89-13)	Cracking due to SCC (titanium only), reduction of heat transfer due to fouling	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. NAPS has no in-scope stainless steel, copper alloy, or titanium heat exchanger tubes exposed to raw water (for components not covered by NRC GL 89-13) that have a heat transfer function in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope concrete, concrete cylinder piping, reinforced concrete, asbestos cement, or cementitious piping, piping components exposed to raw water (for components not covered by NRC GL 89-13) in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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. NAPS has no in-scope HDPE piping, piping components exposed to raw water (for components not covered by NRC GL 89-13) in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), or treated water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope stainless steel fire water storage tanks exposed to air, condensation, soil, or concrete in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope stainless steel fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), or treated water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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)	Consistent with NUREG-2191. Loss of material of stainless steel tanks exposed to air - indoor uncontrolled is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.3.2.2.4.
3.3.1-223	Aluminum underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M41, Buried and Underground Piping and Tanks, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.10)	Not applicable. NAPS has no in-scope aluminum underground piping, piping components, tanks in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope aluminum tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to soil or concrete in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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. NAPS has no in-scope aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air or condensation in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope stainless steel or nickel alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air or condensation in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil or concrete in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil or concrete in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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. NAPS has no in-scope stainless steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to air or condensation in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. Loss of material of stainless steel components exposed to condensation is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.3.2.2.4.
3.3.1-233	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 3.3.2.2.8)	Not applicable. Cracking of aluminum components exposed to air - outdoor, air - indoor uncontrolled, and condensation is addressed in rows 3.3.1-189 and 3.3.1-254. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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. Loss of material of aluminum components exposed to air - indoor uncontrolled and condensation is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.3.2.2.10.
3.3.1-235	Metallic piping, piping components exposed to air-dry (internal)	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M24, Compressed Air Monitoring	No	Consistent with NUREG-2191. In addition to Auxiliary Systems, components in Reactor Vessel, Internals, And Reactor Coolant System (reactor coolant), Engineered Safety Features (residual heat removal), and Steam and Power Conversion System (feedwater, main steam) are aligned to this item.
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. NAPS has no in-scope titanium heat exchanger tubes exposed to treated water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes or piping, piping components exposed to treated water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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	Consistent with NUREG-2191.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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. NAPS has no in-scope titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes or piping, piping components exposed to closed-cycle cooling water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope aluminum heat exchanger components exposed to waste water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-241	Stainless steel, nickel alloy heat exchanger components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.4)	Consistent with NUREG-2191. Loss of material of stainless steel heat exchanger components exposed to air - indoor uncontrolled is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.3.2.2.4.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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. Loss of material of aluminum heat exchanger components exposed to air - indoor uncontrolled, air - outdoor and condensation is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.3.2.2.10.
3.3.1-244	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 - BWR only.
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. Loss of material of aluminum components exposed to air - outdoor, air - indoor uncontrolled, and condensation is addressed in rows 3.3.1-234 and 3.3.1-242. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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. Loss of material of stainless steel underground components is managed by the One-Time Inspection (B2.1.20) program. See further evaluation 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)	Consistent with NUREG-2191. Loss of material of aluminum piping, piping components, tanks exposed to raw water, waste water is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.3.2.2.10.
3.3.1-248	Aluminum piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not applicable. Boric acid corrosion is not an aging effect requiring management for aluminum. The associated NUREG-2191 aging items are not used.
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.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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 applicable. NAPS has no in-scope steel reactor coolant pump oil collection system tanks, piping, piping components exposed to lubricating oil (waste oil) in the Auxiliary Systems. The reactor coolant pump oil collection system is primarily composed of stainless steel components in an environment of waste water. Loss of material for these components is addressed in row 3.3.1-095. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope aluminum piping, piping components exposed to soil or concrete in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
3.3.1-253	PVC piping, piping components exposed to raw water, raw water (potable), treated water, waste water	Loss of material due to wear; flow blockage due to fouling (raw water only)	AMP XI.M20, Open-Cycle Cooling Water System, AMP XI.M27, Fire Water System, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191 with a different aging management program for some components. Loss of material and flow blockage of PVC components exposed to waste water is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. Loss of material of the external surface of PVC components submerged in waste water is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-254	Aluminum heat exchanger components exposed to air, condensation	Cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.8)	Consistent with NUREG-2191. Cracking of aluminum heat exchanger components exposed to air - indoor uncontrolled, air - outdoor, or condensation is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.3.2.2.8.
3.3.1-255	Any material fire damper assemblies exposed to air	Loss of material due to general, pitting, crevice corrosion; cracking due to SCC; hardening, loss of strength, shrinkage due to elastomer degradation	AMP XI.M26, Fire Protection	No	Consistent with NUREG-2191.
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.
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. Flow blockage of metallic, elastomer, fiberglass, HDPE piping, piping components exposed to waste water is addressed in rows 3.3.1-085, 3.3.1-091, 3.3.1-095, and 3.3.1-253. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-259	Aluminum piping, piping components exposed to raw water	Flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. NAPS has no in-scope aluminum piping, piping components exposed to raw water that are required to deliver downstream flow in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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.
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. NAPS has no in-scope titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to closed-cycle cooling water or raw water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.
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. Cracking of titanium heat exchanger tubes exposed to closed-cycle cooling water is addressed in row 3.3.1-238. The associated NUREG-2191 aging items are not used.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-263	Polymeric piping, piping components, ducting, ducting components, seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, soil	Hardening or loss of strength due to polymeric degradation; loss of material due to peeling, delamination, wear; cracking or blistering due to exposure to ultraviolet light, ozone, radiation, or chemical attack; flow blockage due to fouling	AMP XI.M36, External Surfaces Monitoring of Mechanical Components, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191, with a different program for some components. The Buried and Underground Piping and Tanks (B2.1.27) program manages aging of the external surface of underground polymer piping in the security system. The Structures Monitoring (B2.1.34) program manages aging of polymeric components in the Structures and Component Supports (SBO structures for offsite power) are aligned to this item.
3.3.1-265	Steel heat exchanger radiator tubes exposed to fuel oil	Reduction of heat transfer due to fouling	AMP XI.M30, Fuel Oil Chemistry, and XI.M32, One-Time Inspection	No	Not applicable. Reduction of heat transfer of steel heat exchanger tubes in fuel oil is address in row 3.3.1-266 because the tubes are of the same material as the fuel oil storage tank, The associated NUREG-2191 aging items are not used.
3.3.1-266	Steel heat exchanger radiator tubes exposed to fuel oil	Reduction of heat transfer due to fouling	AMP XI.M30, Fuel Oil Chemistry	No	Consistent with NUREG-2191.
3.3.1-267	Subliming compound fireproofing/fire barriers (Thermo-Lag®, 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. Only components in Structures and Component Supports (miscellaneous structural commodities) are aligned to this item.
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. Only components in Structures and Component Supports (miscellaneous structural commodities) are aligned to this item.

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-269	Silicate fireproofing/fire barriers (Marinite®, Kaowool™, Cerafiber®, Cera® blanket, or other similar materials) exposed to air	Loss of material, change in material properties, cracking, delamination, and separation	AMP XI.M26, Fire Protection	No	Consistent with NUREG-2191. Only components in Structures and Component Supports (miscellaneous structural commodities) are aligned to this item.

Results Tables: Auxiliary Systems AMR Results

Table 3.3.2-1 Auxiliary Systems - Fuel Pit Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Expansion joint	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.G.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
Heat exchanger (fuel pit - channel cover)	PB	Steel with stainless steel cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-41	3.3.1-080	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	C
Heat exchanger (fuel pit - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	C
Heat exchanger (fuel pit - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-41	3.3.1-080	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.A3.AP-189	3.3.1-046	A
Heat exchanger (fuel pit - tube)	HT;PB	Stainless steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	C
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	VII.A3.A-101	3.3.1-017	A
					Water Chemistry (B2.1.2)	VII.A3.A-101	3.3.1-017	A

Table 3.3.2-1 Auxiliary Systems - Fuel Pit Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (fuel pit - tubesheet)	PB	Stainless steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	C
Piping, piping components	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.G.AP-221a	3.3.1-006	A
			(E) Concrete	None	None	VII.J.AP-19	3.3.1-202	A
			(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
Pump casing (fuel cask pumpdown)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.G.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
Pump casing (fuel pit cooling)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.G.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.G.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A

Table 3.3.2-1 Plant-Specific Notes: None

Table 3.3.2-2 Auxiliary Systems - Refueling Purification - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Demineralizer shell	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
Filter housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
Flexible hose	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(E) Concrete	None	None	VII.J.AP-19	3.3.1-202	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A

Table 3.3.2-2 Auxiliary Systems - Refueling Purification - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (purification)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
Pump casing (reverse osmosis feed)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
Pump casing (skimmer)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
Reverse osmosis housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
Sample sink	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
Strainer body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A

Table 3.3.2-2 Plant-Specific Notes: None

Table 3.3.2-3 Auxiliary Systems - Primary Grade Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Flow element	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Piping, piping components	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.F.SP-101	3.4.1-016	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Pump casing (primary grade water service)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Pump casing (primary grade water standby)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-3 Auxiliary Systems - Primary Grade Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Strainer body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Valve body	LB;PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-454	3.4.1-106	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Treated water	Loss of material	Selective Leaching (B2.1.21)	VII.C2.AP-32	3.3.1-072	A
					One-Time Inspection (B2.1.20)	VIII.F.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.F.SP-101	3.4.1-016	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-3 Plant-Specific Notes: None

Table 3.3.2-4 Auxiliary Systems - Helium Vacuum Drying - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Fittings (KF piping clamp)	LB	Aluminum	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.A-451a	3.3.1-189	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-763a	3.3.1-234	A
Piping, piping components	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(E) Concrete	None	None	VII.J.AP-19	3.3.1-202	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A
Valve body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A3.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A3.AP-79	3.3.1-125	A

Table 3.3.2-4 Plant-Specific Notes: None

Table 3.3.2-5 Auxiliary Systems - Fuel Handling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Blind flange (fuel transfer tube)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-38	3.5.1-010	C
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-38	3.5.1-010	C
				Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
Bolting	PB	Copper alloy	(E) Air – indoor uncontrolled	Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
		Stainless steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Treated borated water	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-423	3.3.1-142	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
Expansion joint	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
Fuel transfer tube	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-38	3.5.1-010	C
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-38	3.5.1-010	C
				Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A

Table 3.3.2-5 Auxiliary Systems - Fuel Handling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Fuel transfer tube enclosure	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-38	3.5.1-010	C
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-38	3.5.1-010	C
				Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
Piping, piping components	PB;SI	Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A, 2
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
Reactor cavity seal ring	PB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A, 1
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Valve body	PB	Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A, 2
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A

Table 3.3.2-5 Plant-Specific Notes:

1. The reactor cavity seal ring is exposed to treated borated water during refueling outages, but is normally exposed to air and can be inspected prior to use.

2. The compressed air supply to the fuel transfer tube leveling jack is not shown on license renewal drawings. The leveling jack is active, not subject to aging management review.

Table 3.3.2-6 Auxiliary Systems - Materials Handling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Stainless steel	(E) Air – indoor uncontrolled	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B5.T-37b	3.5.1-100	A
				Loss of preload	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B2.1.13)	III.B5.TP-261	3.5.1-088	E, 1
			(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.A-99	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.A-99	3.3.1-125	C
				Loss of preload	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B2.1.13)	III.B5.TP-261	3.5.1-088	E, 1
		Steel	(E) Air – indoor uncontrolled	Loss of preload; loss of material; cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B2.1.13)	VII.B.A-730	3.3.1-199	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Crane rails and retaining clips, girders, beams, plates	SS	Stainless steel	(E) Air – indoor uncontrolled	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B5.T-37b	3.5.1-100	A
			(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.A-99	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.A-99	3.3.1-125	C
		Steel	(E) Air – indoor uncontrolled	Cumulative fatigue damage	TLAA	VII.B.A-06	3.3.1-001	A
				Loss of material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B2.1.13)	VII.B.A-07	3.3.1-052	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Lifting devices	SS	Stainless steel	(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.A-99	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.A-99	3.3.1-125	C
		Steel	(E) Air – indoor uncontrolled	Loss of material	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B2.1.13)	VII.B.A-07	3.3.1-052	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A

Table 3.3.2-6 Plant-Specific Notes:

1. Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B2.1.13) program will manage loss of preload of stainless steel structural bolting in cranes.

Table 3.3.2-7 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Annubar	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	B
Annubar (not covered by NRC GL 89-13)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Bolting	LB;PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air – outdoor	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Raw water	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-423	3.3.1-142	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-241	3.3.1-109	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-241	3.3.1-109	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Waste water	Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
				Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-423	3.3.1-142	A
Compressor casing	SI	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C

Table 3.3.2-7 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Expansion joint	PB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Air – indoor uncontrolled	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.A-504	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.AP-76	3.3.1-096	A
			(E) Air – outdoor	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Raw water	Hardening or loss of strength; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.AP-75	3.3.1-085	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.AP-76	3.3.1-096	A
		Stainless steel	(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	B
Filter housing	LB;SI	Polymer	(I) Air – dry	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-797b	3.3.1-263	A
			(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-797a	3.3.1-263	A
			(I) Condensation	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-797b	3.3.1-263	A

Table 3.3.2-7 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Flexible hose	LB;PB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Treated water	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-75	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-76	3.3.1-096	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	B
Flow element	PB;RF	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-196	3.3.1-034	B
		Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-206	3.3.1-034	B
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	B
Flow element (not covered by NRC GL 89-13)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A

Table 3.3.2-7 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (aftercooler shell)	SI	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
Insulation (safety-related heat traced components)	TI	Non-metallic thermal insulation	(E) Air – indoor uncontrolled	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-704	3.3.1-182	A
			(E) Air – outdoor	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-704	3.3.1-182	A
Orifice	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	B
Piping, piping components	LB;PB;SI	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-196	3.3.1-034	B
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-272	3.3.1-095	A, 1
		Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-206	3.3.1-034	B
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 2
		Polymer	(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-797a	3.3.1-263	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-797b	3.3.1-263	A

Table 3.3.2-7 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-400	3.3.1-127	B
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VII.C1.A-409	3.3.1-126	A
		Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Concrete	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A
			(E) Petrolatum corrosion preventive casing filler	None	None	None	None	G, 3

Table 3.3.2-7 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Steel	(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-400	3.3.1-127	B
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	B
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VII.C1.A-409	3.3.1-126	A
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-284	3.3.1-109	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
		Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Concrete	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-416	3.3.1-138	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-414	3.3.1-139	B
						VII.C1.A-400	3.3.1-127	E, 4
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A

Table 3.3.2-7 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components (not covered by NRC GL 89-13)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Pump casing (auxiliary service water)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	B
Pump casing (chemical addition makeup)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.A-55	3.3.1-066	E, 2
Pump casing (chemical addition)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.A-33	3.3.1-064	E, 2
					Selective Leaching (B2.1.21)	VII.C2.AP-31	3.3.1-072	A
Pump casing (heating and ventilation)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	B

Table 3.3.2-7 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (radiation monitoring)	PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-196	3.3.1-034	B
		Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Pump casing (radiation monitoring) (not covered by NRC GL 89-13)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Pump casing (screen wash)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	B
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	B
Pump casing (service water sump)	LB	Gray cast iron	(E) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-724	3.3.1-072	A
					External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-724	3.3.1-072	A
					External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	A

Table 3.3.2-7 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (service water)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	B
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	B
Pump casing (sump pump)	LB	Ductile iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-547	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Pump casing (tie-in vault sump)	LB	Gray cast iron	(E) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-724	3.3.1-072	A
					External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-724	3.3.1-072	A
					External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	A
Pump casing (transfer drain) (not covered by NRC GL 89-13)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-51	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Radiation monitor housing	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	C
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	C

Table 3.3.2-7 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Radiation monitor housing (not covered by NRC GL 89-13)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	C
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	C
Separator	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A
Spray nozzle	PB;SP	Stainless steel	(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	B
Strainer body	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	B
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	B
Strainer body (not covered by NRC GL 89-13)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Strainer element	FLT	Nickel alloy	(E) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-206	3.3.1-034	B
		Stainless steel	(E) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	B

Table 3.3.2-7 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (air receiver)	PB	Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Tank (chemical mixing chamber)	LB	Polymer	(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-797a	3.3.1-263	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-797b	3.3.1-263	A
Tank (descant dryer)	SI	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A
Tank (polymer storage)	LB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Treated water	Loss of material	Selective Leaching (B2.1.21)	VII.C2.AP-32	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.A.SP-101	3.4.1-016	E, 2

Table 3.3.2-7 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Copper alloy	(I) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-196	3.3.1-034	B
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-272	3.3.1-095	A, 1
		Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-778	3.3.1-249	C
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.A-33	3.3.1-064	E, 2
					Selective Leaching (B2.1.21)	VII.C2.AP-31	3.3.1-072	A
		Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-206	3.3.1-034	B

Table 3.3.2-7 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Polymer	(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-797a	3.3.1-263	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-797b	3.3.1-263	A
		Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	B
		Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-194	3.3.1-037	B
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.A-33	3.3.1-064	E, 2

Table 3.3.2-7 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Steel	(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
		Zinc	(E) Air – indoor uncontrolled	None	None	VII.J.A-712	3.3.1-167	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	None	None	G
Valve body (not covered by NRC GL 89-13)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A

Table 3.3.2-7 Plant-Specific Notes:

1. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

2. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program is used instead of the Water Chemistry (B2.1.2) program to manage loss of material in this treated water environment, which is a chemical solution environment associated with the chemical feed portion of the service water system.

3. Petrolatum (petroleum jelly) is used as a corrosion-inhibiting filler in the annular space surrounding a buried, sleeved service water system pipe. Petrolatum provides a barrier to water intrusion and is an anti-foulant.

4. The Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program will manage recurring internal corrosion of internally coated piping components.

Table 3.3.2-8 Auxiliary Systems - Bearing Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
Expansion joint	LB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Raw water	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-75	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-76	3.3.1-096	A
Flexible hose	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Piping, piping components	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-271	3.3.1-093	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VII.C1.A-409	3.3.1-126	A

Table 3.3.2-8 Auxiliary Systems - Bearing Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Polymer	(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-797a	3.3.1-263	A
			(I) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.A-797b	3.3.1-263	A
			(I) Raw water	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.A-797b	3.3.1-263	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.A-797b	3.3.1-263	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-400	3.3.1-127	E, 3
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 1
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VII.C1.A-409	3.3.1-126	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 2
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-400	3.3.1-127	E, 3
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 1
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VII.C1.A-409	3.3.1-126	A

Table 3.3.2-8 Auxiliary Systems - Bearing Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (bearing cooling chemical addition)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 2
Pump casing (bearing cooling makeup)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-271	3.3.1-093	A
Pump casing (bearing cooling mechanical chiller)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-51	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Pump casing (bearing cooling water)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-51	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Pump casing (central condenser water)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Sight glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Raw water	None	None	VII.J.AP-50	3.3.1-117	A
Sight glass (body)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-271	3.3.1-093	A

Table 3.3.2-8 Auxiliary Systems - Bearing Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Strainer body	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-271	3.3.1-093	A
		Polymer	(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-797a	3.3.1-263	A
			(I) Raw water	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.A-797b	3.3.1-263	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Tank (brominator)	LB	Polymer	(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-797a	3.3.1-263	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.A-797b	3.3.1-263	A
Tank (chemical addition surge)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-162	3.4.1-083	E, 2
Tank (chemical addition)	LB	Polymer	(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-797a	3.3.1-263	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.A-797b	3.3.1-263	A

Table 3.3.2-8 Auxiliary Systems - Bearing Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-271	3.3.1-093	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.A.SP-101	3.4.1-016	E, 2
		Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-51	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
		Polymer	(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-797a	3.3.1-263	A
			(I) Raw water	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.A-797b	3.3.1-263	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.A-797b	3.3.1-263	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 1
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 2
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-400	3.3.1-127	E, 3
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 1

Table 3.3.2-8 Plant-Specific Notes:

1. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

2. This treated water environment is associated with the bearing cooling system chemical addition components, which is managed by the Inspection of Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program instead of the Water Chemistry (B2.1.2) program.

3. Recurring internal corrosion of steel and stainless steel piping components exposed to raw water is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program, instead of the Open-Cycle Cooling Water System (B2.1.11) program.

Table 3.3.2-9 Auxiliary Systems - Circulating Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Raw water	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-423	3.3.1-142	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
Expansion joint	LB;PB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Raw water	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.AP-75	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.AP-76	3.3.1-096	A
Heat exchanger (condenser waterbox)	LB	Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-416	3.3.1-138	B, 2
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-414	3.3.1-139	B
Insulation (safety-related heat traced components)	TI	Non-metallic thermal insulation	(E) Air – indoor uncontrolled	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-704	3.3.1-182	A
Piping, piping components	LB;PB	Fiberglass	(E) Air – indoor uncontrolled	Cracking, blistering, loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-720	3.3.1-150	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-719	3.3.1-082	A
			(I) Raw water	Cracking, blistering, loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-460	3.3.1-175	A

Table 3.3.2-9 Auxiliary Systems - Circulating Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Gray cast iron with internal lining	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-416	3.3.1-138	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-414	3.3.1-139	B
						VII.C1.A-415	3.3.1-140	B
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 1
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Concrete	None	None	VII.J.AP-282	3.3.1-112	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 1
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VII.C1.A-409	3.3.1-126	A
Pump casing (amertap)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-51	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A

Table 3.3.2-9 Auxiliary Systems - Circulating Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (screen wash)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Strainer body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Strainer body (cover)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-51	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Tank (ball collector cover)	LB	Aluminum	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.A-451a	3.3.1-189	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-763a	3.3.1-234	A
			(I) Raw water	Cracking	One-Time Inspection (B2.1.20)	VII.C1.A-451a	3.3.1-189	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-776b	3.3.1-247	A
Tank (ball collector)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A

Table 3.3.2-9 Auxiliary Systems - Circulating Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-271	3.3.1-093	A
		Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-51	3.3.1-072	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 1
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 1
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 1

Table 3.3.2-9 Plant-Specific Notes:

1. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

2. The condenser waterboxes are lined with an epoxy coal tar, not cementitious. Therefore, loss of material and cracking are not aging effects requiring management.

Table 3.3.2-10 Auxiliary Systems - Vacuum Priming - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Ejector (body)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F1.A-566	3.3.1-169	A
Ejector (nozzle)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F1.A-748	3.3.1-219	A
					Water Chemistry (B2.1.2)	VII.F1.A-748	3.3.1-219	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-567	3.3.1-170	A
					Water Chemistry (B2.1.2)	VII.F1.A-567	3.3.1-170	A
Expansion joint	LB;PB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Air – indoor uncontrolled	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-504	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.AP-103	3.3.1-096	A
Fan housing (gland steam condenser)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
Filter housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A

Table 3.3.2-10 Auxiliary Systems - Vacuum Priming - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Flexible hose	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Piping, piping components	LB;PB;SI	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-26	3.3.1-055	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Steam	Cumulative fatigue damage	TLAA	VII.E1.A-34	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F1.A-566	3.3.1-169	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.B1.S-15	3.4.1-005	A

Table 3.3.2-10 Auxiliary Systems - Vacuum Priming - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (vacuum priming)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-51	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Sight glass	LB;SI	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Condensation	None	None	VII.J.AP-97	3.3.1-117	A
			(I) Raw water	None	None	VII.J.AP-50	3.3.1-117	A
			(I) Treated water	None	None	VII.J.AP-51	3.3.1-117	A
Sight glass (body)	LB;SI	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-26	3.3.1-055	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A

Table 3.3.2-10 Auxiliary Systems - Vacuum Priming - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Silencer / separator	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Strainer body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-26	3.3.1-055	A
Tank (air separator)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-75	3.4.1-012	A
					Water Chemistry (B2.1.2)	VIII.E.SP-75	3.4.1-012	A
Tank (vacuum priming seal)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Tank (vacuum priming)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A, 1
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A, 1
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 1
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A, 1
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A, 1
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 1

Table 3.3.2-10 Auxiliary Systems - Vacuum Priming - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Condensation	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
		Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-26	3.3.1-055	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-51	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F1.A-566	3.3.1-169	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F1.A-748	3.3.1-219	A
					Water Chemistry (B2.1.2)	VII.F1.A-748	3.3.1-219	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-567	3.3.1-170	A
					Water Chemistry (B2.1.2)	VII.F1.A-567	3.3.1-170	A

Table 3.3.2-10 Auxiliary Systems - Vacuum Priming - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-26	3.3.1-055	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A

Table 3.3.2-10 Plant-Specific Notes:

1. The Unit 1 vacuum priming tank is stainless steel. The Unit 2 vacuum priming tank is steel.

Table 3.3.2-11 Auxiliary Systems - Domestic Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB	Copper alloy	(E) Air – indoor uncontrolled	Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Flexible hose	LB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Raw water	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.AP-75	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.AP-76	3.3.1-096	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Piping (eyewash / safety shower assembly)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A

Table 3.3.2-11 Auxiliary Systems - Domestic Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-271	3.3.1-093	A
		Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-51	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Pump casing (hot water circulating)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-271	3.3.1-093	A
Tank (air chamber)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-271	3.3.1-093	A
Tank (hot water storage)	LB	Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-416	3.3.1-138	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-414	3.3.1-139	B

Table 3.3.2-11 Auxiliary Systems - Domestic Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-271	3.3.1-093	A
		Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-51	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Valve body (eyewash / safety shower assembly)	LB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Raw water	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-473b	3.3.1-160	E
				Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-47	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A

Table 3.3.2-11 Plant-Specific Notes: None

Table 3.3.2-12 Auxiliary Systems - Component Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Expansion joint	PB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Closed–cycle cooling water	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.AP-259	3.3.1-085	A
Flexible hose	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
Heat exchanger (component cooling - channel)	PB	Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-41	3.3.1-080	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-416	3.3.1-138	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C1.A-414	3.3.1-139	B
		Steel with titanium (ASTM Grade 1) cladding	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-41	3.3.1-080	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Cracking; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-152a	3.3.1-123	B

Table 3.3.2-12 Auxiliary Systems - Component Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (component cooling - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-41	3.3.1-080	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (component cooling - tube)	HT;PB	Stainless steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	D
				Reduction of heat transfer	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-187	3.3.1-042	B
		Titanium (ASTM Grade 2)	(E) Closed–cycle cooling water	Cracking; reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.A-767	3.3.1-238	A
			(I) Raw water	Cracking; reduction of heat transfer	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-187	3.3.1-042	B
Heat exchanger (component cooling - tubesheet)	PB	Steel with stainless steel cladding	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	D
		Steel with titanium (ASTM Grade 1) cladding	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
			(I) Raw water	Cracking; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-152a	3.3.1-123	B
Orifice	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A

Table 3.3.2-12 Auxiliary Systems - Component Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Copper alloy	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
Pump casing (component cooling)	PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	A
Radiation monitor housing	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
Sight glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Closed–cycle cooling water	None	None	VII.J.AP-166	3.3.1-117	A

Table 3.3.2-12 Auxiliary Systems - Component Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Sight glass (body)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
Tank (surge)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
Valve body	LB;PB;SI	Copper alloy	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
		Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	A
					Selective Leaching (B2.1.21)	VII.C2.AP-43	3.3.1-072	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A

Table 3.3.2-12 Plant-Specific Notes: None

Table 3.3.2-13 Auxiliary Systems - Neutron Shield Tank Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Heat exchanger (neutron shield tank cooler - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
Heat exchanger (neutron shield tank cooler - shell)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
Heat exchanger (neutron shield tank cooler - tube)	HT;PB	Stainless steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	A
Heat exchanger (neutron shield tank cooler - tubesheet)	PB	Stainless steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C

Table 3.3.2-13 Auxiliary Systems - Neutron Shield Tank Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A, 1
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-73	3.4.1-014	E, 1
Pump casing (neutron shield tank cooling)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
Strainer body	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
Tank (neutron shield surge)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A

Table 3.3.2-13 Auxiliary Systems - Neutron Shield Tank Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A, 1
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-73	3.4.1-014	E, 1

Table 3.3.2-13 Plant-Specific Notes:

1. The treated water environment is applicable to the chemical addition components connected to the neutron shield surge tank.

Table 3.3.2-14 Auxiliary Systems - Instrument Air - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Filter housing	SI	Copper alloy (>15% Zn)	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
Flexible hose (portable vent rig)	PB	Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
Heat exchanger (compressor inter, after, and oil cooler - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-40	3.3.1-080	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (instrument air compressor - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	C
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Heat exchanger (instrument air compressor - shell)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	C
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
Heat exchanger (instrument air compressor - tube and tubesheet)	PB	Stainless steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C, 1
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 1

Table 3.3.2-14 Auxiliary Systems - Instrument Air - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Copper alloy	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Condensation	None	None	VII.J.AP-144	3.3.1-114	A
		Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
		Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A
Pump casing (compressor cooling skid)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
Sight glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Closed–cycle cooling water	None	None	VII.J.AP-166	3.3.1-117	A

Table 3.3.2-14 Auxiliary Systems - Instrument Air - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Sight glass (body)	LB	Aluminum	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.A-451a	3.3.1-189	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-763a	3.3.1-234	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-254	3.3.1-048	A
Strainer body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A
Tank (air accumulator)	PB	Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Tank (portable air bottle)	PB	Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Trap body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A

Table 3.3.2-14 Auxiliary Systems - Instrument Air - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Copper alloy	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Condensation	None	None	VII.J.AP-144	3.3.1-114	A
		Copper alloy (>15% Zn)	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
		Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
		Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A

Table 3.3.2-14 Plant-Specific Notes:

1. Heat exchanger tubes do not have a heat transfer function.

Table 3.3.2-15 Auxiliary Systems - Service Air - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Piping, piping components	LB;PB;SI	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Condensation	None	None	VII.J.AP-144	3.3.1-114	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A
Trap body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A

Table 3.3.2-15 Auxiliary Systems - Service Air - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Condensation	None	None	VII.J.AP-144	3.3.1-114	A
		Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Condensation	None	None	VII.J.AP-144	3.3.1-114	A, 1
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.D.A-26	3.3.1-055	A

Table 3.3.2-15 Plant-Specific Notes:

1. Cracking of copper alloy (>15% Zn) in air and condensation environments requires the presence of ammonia-based compounds. In indoor air, such compounds could be conveyed to external surfaces of components via leakage through the insulation from bolted connections. However, internal surfaces of components are not exposed to contamination from external leakage sources. Therefore, internal cracking of these components is not expected.

Table 3.3.2-16 Auxiliary Systems - Primary & Secondary Plant Gas Supplies - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Filter housing	SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
Flexible hose	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
Orifice	SI	Stainless steel	(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
Piping, piping components	LB;PB;SI	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A

Table 3.3.2-16 Auxiliary Systems - Primary & Secondary Plant Gas Supplies - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
			(I) Steam	Cumulative fatigue damage	TLAA	VII.E1.A-34	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F2.A-566	3.3.1-169	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.B1.S-15	3.4.1-005	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
Tank (nitrogen reserve)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A

Table 3.3.2-16 Auxiliary Systems - Primary & Secondary Plant Gas Supplies - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Copper alloy (>15% Zn)	(E) Air – outdoor	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	VII.D.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.D.AP-221a	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-748	3.3.1-219	A
					Water Chemistry (B2.1.2)	VII.F2.A-748	3.3.1-219	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-567	3.3.1-170	A
					Water Chemistry (B2.1.2)	VII.F2.A-567	3.3.1-170	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F2.A-566	3.3.1-169	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A

Table 3.3.2-16 Plant-Specific Notes: None

Table 3.3.2-17 Auxiliary Systems - Penetration Electrical - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
Valve body	PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	A

Table 3.3.2-17 Plant-Specific Notes: None

Table 3.3.2-18 Auxiliary Systems - Leakage Monitoring - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	PB;SI	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
Valve body	PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A

Table 3.3.2-18 Plant-Specific Notes: None

Table 3.3.2-19 Auxiliary Systems - Chemical & Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Blender	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-82	3.3.1-028	A
					Water Chemistry (B2.1.2)	VII.E1.AP-82	3.3.1-028	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Bolting	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	Bolting Integrity (B2.1.9)	VII.I.A-426	3.3.1-145	A
				Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Demineralizer shell	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Filter housing (boric acid)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-82	3.3.1-028	A
					Water Chemistry (B2.1.2)	VII.E1.AP-82	3.3.1-028	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Filter housing (letdown)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A

Table 3.3.2-19 Auxiliary Systems - Chemical & Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Filter housing (reactor coolant)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Filter housing (seal injection)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Filter housing (seal water return)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Flexible hose	LB;PB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Treated water	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-75	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-76	3.3.1-096	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-138	3.3.1-100	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-19 Auxiliary Systems - Chemical & Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Flow element	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 1
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
		Stainless steel with internal lining	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water >60°C (>140°F)	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	V.D1.E-401	3.2.1-072	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	V.D1.E-414	3.2.1-073	B
Flow element (flange)	PB	Steel with internal lining	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Treated borated water >60°C (>140°F)	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	V.D1.E-401	3.2.1-072	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	V.D1.E-414	3.2.1-073	B
Heat exchanger (batch tank panel steam coils)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-566	3.3.1-169	C
					Water Chemistry (B2.1.2)	VII.F2.A-566	3.3.1-169	C

Table 3.3.2-19 Auxiliary Systems - Chemical & Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (charging pump gear box lubricating oil - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	D
Heat exchanger (charging pump gear box lubricating oil - shell)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-138	3.3.1-100	C
					One-Time Inspection (B2.1.20)	VII.E1.AP-138	3.3.1-100	C
Heat exchanger (charging pump gear box lubricating oil - tube)	HT;PB	Copper alloy	(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-133	3.3.1-099	C
					One-Time Inspection (B2.1.20)	VII.E1.AP-133	3.3.1-099	C
				Reduction of heat transfer	Lubricating Oil Analysis (B2.1.26)	VII.E1.A-791	3.3.1-257	A
					One-Time Inspection (B2.1.20)	VII.E1.A-791	3.3.1-257	A
			(I) Raw water	Loss of material	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-179	3.3.1-038	B
				Reduction of heat transfer	Open-Cycle Cooling Water System (B2.1.11)	VIII.G.SP-56	3.4.1-022	B
Heat exchanger (charging pump gear box lubricating oil - tubesheet)	PB	Stainless steel	(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-138	3.3.1-100	C
					One-Time Inspection (B2.1.20)	VII.E1.AP-138	3.3.1-100	C
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	D
Heat exchanger (charging pump lubricating oil - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	D
Heat exchanger (charging pump lubricating oil - shell)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-138	3.3.1-100	C
					One-Time Inspection (B2.1.20)	VII.E1.AP-138	3.3.1-100	C

Table 3.3.2-19 Auxiliary Systems - Chemical & Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (charging pump lubricating oil - tube)	HT;PB	Copper alloy	(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-133	3.3.1-099	C
					One-Time Inspection (B2.1.20)	VII.E1.AP-133	3.3.1-099	C
				Reduction of heat transfer	Lubricating Oil Analysis (B2.1.26)	VII.E1.A-791	3.3.1-257	A
					One-Time Inspection (B2.1.20)	VII.E1.A-791	3.3.1-257	A
			(I) Raw water	Loss of material	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-179	3.3.1-038	B
				Reduction of heat transfer	Open-Cycle Cooling Water System (B2.1.11)	VIII.G.SP-56	3.4.1-022	B
Heat exchanger (charging pump lubricating oil - tubesheet)	PB	Stainless steel	(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-138	3.3.1-100	C
					One-Time Inspection (B2.1.20)	VII.E1.AP-138	3.3.1-100	C
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	D
Heat exchanger (excess letdown - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (excess letdown - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (excess letdown - tube)	HT;PB	Stainless steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	VII.E1.A-101	3.3.1-017	A
					Water Chemistry (B2.1.2)	VII.E1.A-101	3.3.1-017	A

Table 3.3.2-19 Auxiliary Systems - Chemical & Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (excess letdown - tubesheet)	PB	Stainless steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (nonregenerative - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (nonregenerative - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (nonregenerative - tube)	HT;PB	Stainless steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	A
			(I) Treated borated water >60°C (>140°F)	Cracking	Water Chemistry (B2.1.2)	VII.E1.A-69	3.3.1-003	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	VII.E1.A-101	3.3.1-017	A
					Water Chemistry (B2.1.2)	VII.E1.A-101	3.3.1-017	A

Table 3.3.2-19 Auxiliary Systems - Chemical & Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (nonregenerative - tubesheet)	PB	Stainless steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (regenerative - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Treated borated water >60°C (>140°F)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	VII.E1.AP-119	3.3.1-008	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Cumulative fatigue damage	TLAA	VII.E1.A-100	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (regenerative - shell)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Treated borated water >60°C (>140°F)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	VII.E1.AP-119	3.3.1-008	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Cumulative fatigue damage	TLAA	VII.E1.A-100	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C

Table 3.3.2-19 Auxiliary Systems - Chemical & Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (regenerative - tube)	HT;PB	Stainless steel	(E) Treated borated water >60°C (>140°F)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	VII.E1.AP-119	3.3.1-008	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Cumulative fatigue damage	TLAA	VII.E1.A-100	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	VII.E1.A-101	3.3.1-017	A
					Water Chemistry (B2.1.2)	VII.E1.A-101	3.3.1-017	A
			(I) Treated borated water >60°C (>140°F)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	VII.E1.AP-119	3.3.1-008	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	VII.E1.A-101	3.3.1-017	A
					Water Chemistry (B2.1.2)	VII.E1.A-101	3.3.1-017	A
Heat exchanger (regenerative - tubesheet)	PB	Stainless steel	(E) Treated borated water >60°C (>140°F)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	VII.E1.AP-119	3.3.1-008	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	VII.E1.AP-119	3.3.1-008	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Cumulative fatigue damage	TLAA	VII.E1.A-100	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A

Table 3.3.2-19 Auxiliary Systems - Chemical & Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (seal water - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (seal water - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (seal water - tube)	HT;PB	Stainless steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	VII.E1.A-101	3.3.1-017	A
					Water Chemistry (B2.1.2)	VII.E1.A-101	3.3.1-017	A
Heat exchanger (seal water - tubesheet)	PB	Stainless steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Insulation (containment penetration)	TI	Non-metallic thermal insulation	(E) Air – indoor uncontrolled	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-704	3.3.1-182	A
Insulation (safety-related heat traced components)	TI	Non-metallic thermal insulation	(E) Air – indoor uncontrolled	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-704	3.3.1-182	A
			(E) Air – outdoor	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-704	3.3.1-182	A

Table 3.3.2-19 Auxiliary Systems - Chemical & Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Orifice	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 1
				Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.A-54	3.3.1-040	B
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	V.D1.E-24	3.2.1-005	A
						VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-82	3.3.1-028	A
					Water Chemistry (B2.1.2)	VII.E1.AP-82	3.3.1-028	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-19 Auxiliary Systems - Chemical & Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Stainless steel	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
			(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-138	3.3.1-100	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-138	3.3.1-100	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 1
			(E) Soil	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.A-425	3.3.1-144	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-137	3.3.1-107	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-82	3.3.1-028	A
					Water Chemistry (B2.1.2)	VII.E1.AP-82	3.3.1-028	A
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VII.E1.A-407	3.3.1-126	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 2
					One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-19 Auxiliary Systems - Chemical & Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Stainless steel	(E) Underground	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.A-714b	3.3.1-146	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.A-775b	3.3.1-246	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Steam	Cumulative fatigue damage	TLAA	VII.E1.A-34	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F2.A-566	3.3.1-169	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.B1.S-15	3.4.1-005	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E1.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A
Piping, piping components (Class 1 <NPS 4)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Reactor coolant	Cracking	ASME Code Class 1 Small-Bore Piping (B2.1.22)	IV.C2.RP-235	3.1.1-039	A
					ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-235	3.1.1-039	A
					Water Chemistry (B2.1.2)	IV.C2.RP-235	3.1.1-039	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Piping, piping components (Class 1)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.3.2-19 Auxiliary Systems - Chemical & Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (boric acid transfer)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-82	3.3.1-028	A
					Water Chemistry (B2.1.2)	VII.E1.AP-82	3.3.1-028	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Pump casing (charging pump gear drive lubricating oil)	PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-127	3.3.1-097	A
Pump casing (charging pump motor driven lubricating oil)	PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-133	3.3.1-099	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-133	3.3.1-099	A
Pump casing (charging pump shaft driven lubricating oil)	PB	Steel	(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-127	3.3.1-097	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-127	3.3.1-097	A
Pump casing (charging)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	VII.E1.AP-115	3.3.1-007	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Pump casing (zinc addition)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 2

Table 3.3.2-19 Auxiliary Systems - Chemical & Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Sight glass	PB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Lubricating oil	None	None	VII.J.AP-15	3.3.1-117	A
Sight glass (body)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-138	3.3.1-100	A
Strainer body	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-127	3.3.1-097	A
Strainer element	FLT	Stainless steel	(E) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-82	3.3.1-028	A
					Water Chemistry (B2.1.2)	VII.E1.AP-82	3.3.1-028	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
		Steel	(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-127	3.3.1-097	A
Tank (boric acid batch)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-82	3.3.1-028	A
					Water Chemistry (B2.1.2)	VII.E1.AP-82	3.3.1-028	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A

Table 3.3.2-19 Auxiliary Systems - Chemical & Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (boric acid)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-82	3.3.1-028	A
					Water Chemistry (B2.1.2)	VII.E1.AP-82	3.3.1-028	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Tank (charging pump lubricating oil)	PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-127	3.3.1-097	A
Tank (chemical mixing)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 2
Tank (resin fill)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 2
Tank (volume control)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Tank (zinc addition)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 2

Table 3.3.2-19 Auxiliary Systems - Chemical & Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Trap body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E1.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A
Valve body	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.E1.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.E1.AP-138	3.3.1-100	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 1
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-82	3.3.1-028	A
					Water Chemistry (B2.1.2)	VII.E1.AP-82	3.3.1-028	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 2
					One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-19 Auxiliary Systems - Chemical & Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F2.A-566	3.3.1-169	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E1.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A
Valve body (Class 1)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-09	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.R-09	3.1.1-033	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.3.2-19 Plant-Specific Notes:

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program will manage aging of nonsafety-related stainless steel components in raw water that have a leakage boundary function.

2. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program will manage aging of nonsafety-related stainless steel components in treated water that corresponds to chemical mixing/addition tanks and piping components.

Table 3.3.2-20 Auxiliary Systems - Boron Recovery - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Demineralizer shell (boron cleanup)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
Demineralizer shell (cesium removal)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
Evaporator shell	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-748	3.3.1-219	C
					Water Chemistry (B2.1.2)	VII.F2.A-748	3.3.1-219	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-567	3.3.1-170	C
					Water Chemistry (B2.1.2)	VII.F2.A-567	3.3.1-170	C
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	C
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	C
Filter housing (boron cleanup)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A

Table 3.3.2-20 Auxiliary Systems - Boron Recovery - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Filter housing (boron recovery)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
Filter housing (evaporator bottoms)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
Heat exchanger (evaporator bottoms cooler - channel)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	C
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	C
Heat exchanger (evaporator bottoms cooler - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (evaporator bottoms cooler - tube and tubesheet)	PB	Stainless steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	C
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	C

Table 3.3.2-20 Auxiliary Systems - Boron Recovery - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (evaporator distillate cooler - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	C
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	C
Heat exchanger (evaporator distillate cooler - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (evaporator distillate cooler - tube and tubesheet)	PB	Stainless steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	C
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	C
Heat exchanger (evaporator overhead condenser - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
Heat exchanger (evaporator overhead condenser - shell)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-748	3.3.1-219	C
					Water Chemistry (B2.1.2)	VII.F2.A-748	3.3.1-219	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-567	3.3.1-170	C
					Water Chemistry (B2.1.2)	VII.F2.A-567	3.3.1-170	C
Heat exchanger (evaporator overhead condenser - tube and tubesheet)	PB	Stainless steel	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(E) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-748	3.3.1-219	C
					Water Chemistry (B2.1.2)	VII.F2.A-748	3.3.1-219	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-567	3.3.1-170	C
					Water Chemistry (B2.1.2)	VII.F2.A-567	3.3.1-170	C

Table 3.3.2-20 Auxiliary Systems - Boron Recovery - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (evaporator reboiler - channel cover)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Heat exchanger (evaporator reboiler - channel)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	C
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	C
Heat exchanger (evaporator reboiler - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	C
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	C
Heat exchanger (sample cooler - outer tube)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.E1.AP-199	3.3.1-046	A
Heat exchanger (stripper feed - channel)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	C
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	C

Table 3.3.2-20 Auxiliary Systems - Boron Recovery - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (stripper feed - shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	C
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	C
Heat exchanger (stripper steam heater - channel cover)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Heat exchanger (stripper steam heater - channel)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	C
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	C
Heat exchanger (stripper steam heater - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	C
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	C
Heat exchanger (stripper trim cooler - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	C

Table 3.3.2-20 Auxiliary Systems - Boron Recovery - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (stripper trim cooler - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (stripper trim cooler - tube and tubesheet)	PB	Stainless steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	C
Heat exchanger (stripper vent chiller - channel)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
Heat exchanger (stripper vent chiller - shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-748	3.3.1-219	C
					Water Chemistry (B2.1.2)	VII.F2.A-748	3.3.1-219	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-567	3.3.1-170	C
					Water Chemistry (B2.1.2)	VII.F2.A-567	3.3.1-170	C
Heat exchanger (stripper vent condenser - channel)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-748	3.3.1-219	C
					Water Chemistry (B2.1.2)	VII.F2.A-748	3.3.1-219	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-567	3.3.1-170	C
					Water Chemistry (B2.1.2)	VII.F2.A-567	3.3.1-170	C

Table 3.3.2-20 Auxiliary Systems - Boron Recovery - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (stripper vent condenser - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heater housing (evaporator bottoms cooler preheater)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-748	3.3.1-219	A
					Water Chemistry (B2.1.2)	VII.F2.A-748	3.3.1-219	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-567	3.3.1-170	A
					Water Chemistry (B2.1.2)	VII.F2.A-567	3.3.1-170	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A

Table 3.3.2-20 Auxiliary Systems - Boron Recovery - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-748	3.3.1-219	A
					Water Chemistry (B2.1.2)	VII.F2.A-748	3.3.1-219	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-567	3.3.1-170	A
					Water Chemistry (B2.1.2)	VII.F2.A-567	3.3.1-170	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
Pump casing (evaporator bottoms cooler circulating)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A

Table 3.3.2-20 Auxiliary Systems - Boron Recovery - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (evaporator bottoms tank circulating)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
Pump casing (evaporator bottoms)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
Pump casing (evaporator circulating)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
Pump casing (evaporator distillate)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A

Table 3.3.2-20 Auxiliary Systems - Boron Recovery - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (stripper circulation)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
Pump casing (stripper discharge)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
Pump casing (test tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
Rupture disc	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-748	3.3.1-219	A
					Water Chemistry (B2.1.2)	VII.F2.A-748	3.3.1-219	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-567	3.3.1-170	A
					Water Chemistry (B2.1.2)	VII.F2.A-567	3.3.1-170	A

Table 3.3.2-20 Auxiliary Systems - Boron Recovery - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Strainer body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
Tank (distillate accumulator)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
Tank (evaporator bottoms)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A

Table 3.3.2-20 Auxiliary Systems - Boron Recovery - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (gas stripper)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-748	3.3.1-219	A
					Water Chemistry (B2.1.2)	VII.F2.A-748	3.3.1-219	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-567	3.3.1-170	A
					Water Chemistry (B2.1.2)	VII.F2.A-567	3.3.1-170	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-748	3.3.1-219	A
					Water Chemistry (B2.1.2)	VII.F2.A-748	3.3.1-219	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-567	3.3.1-170	A
					Water Chemistry (B2.1.2)	VII.F2.A-567	3.3.1-170	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.A2.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.A2.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	V.C.EP-63	3.2.1-022	A
					Water Chemistry (B2.1.2)	V.C.EP-63	3.2.1-022	A

Table 3.3.2-20 Auxiliary Systems - Boron Recovery - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A

Table 3.3.2-20 Plant-Specific Notes: None

Table 3.3.2-21 Auxiliary Systems - Sampling System - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Demineralizer shell	LB	Polymer	(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-797a	3.3.1-263	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.A-797b	3.3.1-263	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Filter housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Flow indicator	LB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Treated water	None	None	VII.J.AP-51	3.3.1-117	A
			(I) Waste water	None	None	VII.J.AP-277	3.3.1-119	A
Flow indicator (body)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-21 Auxiliary Systems - Sampling System - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (chiller bath)	LB	Stainless steel	(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-80	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-80	3.4.1-085	A
Heat exchanger (heating bath)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
			(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-80	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-80	3.4.1-085	A
Heat exchanger (sample bath chiller condenser water side)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	A
Heat exchanger (sample bath chiller evaporator water side)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	A

Table 3.3.2-21 Auxiliary Systems - Sampling System - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (sample cooler - outer tube/shell)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	C
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	C
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-101	3.4.1-016	C
					Water Chemistry (B2.1.2)	VIII.A.SP-101	3.4.1-016	C
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-80	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-80	3.4.1-085	A
Level glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Treated water	None	None	VII.J.AP-51	3.3.1-117	A
Level glass (housing)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-21 Auxiliary Systems - Sampling System - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(E) Condensation	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.A.SP-101	3.4.1-016	A
		PVC	(E) Air – indoor uncontrolled	None	None	VII.J.AP-268	3.3.1-119	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-787d	3.3.1-253	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-748	3.3.1-219	A
					Water Chemistry (B2.1.2)	VII.F2.A-748	3.3.1-219	A
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-567	3.3.1-170	A
					Water Chemistry (B2.1.2)	VII.F2.A-567	3.3.1-170	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	A
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A

Table 3.3.2-21 Auxiliary Systems - Sampling System - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Stainless steel	(E) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-88	3.4.1-011	A
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A

Table 3.3.2-21 Auxiliary Systems - Sampling System - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components (Class 1)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.RP-344	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.RP-344	3.1.1-033	A
				Cumulative fatigue damage	TLAA	IV.C2.R-223	3.1.1-009	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A
Pump casing (chiller bath circulating)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.C2.AP-31	3.3.1-072	A
					One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
Pump casing (collection tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Pump casing (flushing)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Pump casing (sample)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-21 Auxiliary Systems - Sampling System - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Radiation monitor housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Sample sink	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Tank (collection)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Valve body	LB;PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Treated water	Loss of material	Selective Leaching (B2.1.21)	VII.C2.AP-32	3.3.1-072	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.A.SP-101	3.4.1-016	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-748	3.3.1-219	A
					Water Chemistry (B2.1.2)	VII.F2.A-748	3.3.1-219	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-567	3.3.1-170	A
					Water Chemistry (B2.1.2)	VII.F2.A-567	3.3.1-170	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A

Table 3.3.2-21 Auxiliary Systems - Sampling System - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Stainless steel	(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A

Table 3.3.2-21 Auxiliary Systems - Sampling System - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body (Class 1)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.C2.R-09	3.1.1-033	A
					Water Chemistry (B2.1.2)	IV.C2.R-09	3.1.1-033	A
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.3.2-21 Plant-Specific Notes: None

Table 3.3.2-22 Auxiliary Systems - Incore Instrumentation - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A

Table 3.3.2-22 Plant-Specific Notes: None

Table 3.3.2-23 Auxiliary Systems - Decontamination - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Piping, piping components	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Valve body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-23 Plant-Specific Notes: None

Table 3.3.2-24 Auxiliary Systems - Drains - Aerated - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB;SI	Stainless steel	(E) Waste water	Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
				Cracking	Bolting Integrity (B2.1.9)	VII.I.A-426	3.3.1-145	A
				Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-423	3.3.1-142	A
		Steel	(E) Waste water	Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
				Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-423	3.3.1-142	A
			(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-241	3.3.1-109	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
Flexible hose	LB;PB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Treated water	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-75	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-76	3.3.1-096	A
			(I) Waste water	Hardening or loss of strength; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-728	3.3.1-085	A, 1
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-550	3.3.1-096	A, 1
Flow totalizer	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-272	3.3.1-095	A

Table 3.3.2-24 Auxiliary Systems - Drains - Aerated - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	PVC	(E) Air – indoor uncontrolled	None	None	VII.J.AP-268	3.3.1-119	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-797b	3.3.1-263	A
			(E) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-787d	3.3.1-253	E, 2
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-787d	3.3.1-253	A
Piping, piping components	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(E) Concrete	None	None	VII.J.AP-19	3.3.1-202	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(E) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-411	3.3.1-135	C
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A, 1

Table 3.3.2-24 Auxiliary Systems - Drains - Aerated - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-284	3.3.1-109	A
			(E) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A, 1
Pump casing (containment mat sump)	PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-724	3.3.1-072	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Pump casing (sump pump)	LB	Gray cast iron	(E) Waste water	Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-724	3.3.1-072	A
					External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-724	3.3.1-072	A
					External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	A
		Stainless steel	(E) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-411	3.3.1-135	A
			(I) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-411	3.3.1-135	A

Table 3.3.2-24 Auxiliary Systems - Drains - Aerated - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Sight glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
Sight glass (body)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Strainer body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Tank (primary vent pot)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A

Table 3.3.2-24 Auxiliary Systems - Drains - Aerated - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	PVC	(E) Air – indoor uncontrolled	None	None	VII.J.AP-268	3.3.1-119	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-797b	3.3.1-263	A
			(E) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-787d	3.3.1-253	E, 2
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-787d	3.3.1-253	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A, 1
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-284	3.3.1-109	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A, 1

Table 3.3.2-24 Plant-Specific Notes:

1. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

2. The External Surfaces Monitoring of Mechanical Components (B2.1.23) program will manage external surfaces of PVC components in waste water.

Table 3.3.2-25 Auxiliary Systems - Drains - Building Services - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Stainless steel	(E) Waste water	Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
				Cracking	Bolting Integrity (B2.1.9)	VII.I.A-426	3.3.1-145	A
				Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-423	3.3.1-142	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
Flexible hose	LB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Waste water	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-728	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-550	3.3.1-096	A
Grating (storm drain)	FLT	Gray cast iron	(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
		Steel	(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Piping, piping components	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-174	3.3.1-108	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-272	3.3.1-095	A
		Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Concrete	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A, 2
				None	None	VII.J.AP-282	3.3.1-112	A, 3
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-547	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A

Table 3.3.2-25 Auxiliary Systems - Drains - Building Services - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Gray cast iron with internal coating	(E) Concrete	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A, 2
				None	None	VII.J.AP-282	3.3.1-112	A, 3
			(I) Waste water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.G.A-416	3.3.1-138	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.G.A-414	3.3.1-139	B
						VII.G.A-415	3.3.1-140	B
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A, 5
Piping, piping components (roof drains)	LB	Fiberglass	(E) Air – indoor uncontrolled	Cracking, blistering, loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-720	3.3.1-150	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-719	3.3.1-082	A
			(I) Waste water	Cracking, blistering, loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-551	3.3.1-175	A
Piping, piping components (storm drain)	FD	Steel	(I) Raw water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A, 4
Pump casing (chiller room sump - case)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(E) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-411	3.3.1-135	A
			(I) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-411	3.3.1-135	A

Table 3.3.2-25 Auxiliary Systems - Drains - Building Services - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (chiller room sump - discharge head)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Pump casing (chiller room sump - suction strainer)	FLT	Steel	(E) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	A
Pump casing (oil drain collection)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-547	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A

Table 3.3.2-25 Auxiliary Systems - Drains - Building Services - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (sump pump)	LB	Copper alloy	(E) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.AP-272	3.3.1-095	E, 1
			(I) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.AP-272	3.3.1-095	E, 1
		Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Waste water	Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-547	3.3.1-072	A
					External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-547	3.3.1-072	A
					External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	A
Pump casing (tunnel sump pump)	LB	Copper alloy	(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-174	3.3.1-108	A
			(E) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.AP-272	3.3.1-095	E, 1
			(I) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.AP-272	3.3.1-095	E, 1
Strainer body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Tank (oil drain collection)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A

Table 3.3.2-25 Auxiliary Systems - Drains - Building Services - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-174	3.3.1-108	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-272	3.3.1-095	A
		Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-547	3.3.1-072	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A, 5

Table 3.3.2-25 Plant-Specific Notes:

1. The External Surfaces Monitoring of Mechanical Components (B2.1.23) program will manage aging of the internal and external surfaces of submerged copper alloy sump pumps. Internal and external environments are such that the external surface condition is representative of the internal surface condition, and this program assignment is similar to that in items VII.E5.A-410 and VII.E5.A-411.

2. Piping that exits concrete into soil is exposed to groundwater.

3. Piping that does not exit concrete into soil is not exposed to groundwater.

4. The function of storm drain piping is to remove water from the yard. The only applicable aging effect is flow blockage, as piping integrity is not required.

5. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

Table 3.3.2-26 Auxiliary Systems - Drains - Gaseous - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Filter housing	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Heat exchanger (primary drains transfer - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
Heat exchanger (primary drains transfer - shell)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-770a	3.3.1-241	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-118	3.3.1-020	A
					Water Chemistry (B2.1.2)	VII.E1.AP-118	3.3.1-020	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (primary drains transfer - tube)	HT;PB	Stainless steel	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-188	3.3.1-050	A
			(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	VII.E1.A-101	3.3.1-017	A
					Water Chemistry (B2.1.2)	VII.E1.A-101	3.3.1-017	A
Heat exchanger (primary drains transfer - tubesheet)	PB	Stainless steel	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(E) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C

Table 3.3.2-26 Auxiliary Systems - Drains - Gaseous - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Pump casing (primary drain transfer)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Strainer body	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Tank (primary drain transfer)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
Tank (Unit 2 level column head tank)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A

Table 3.3.2-26 Auxiliary Systems - Drains - Gaseous - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A

Table 3.3.2-26 Plant-Specific Notes: None

Table 3.3.2-27 Auxiliary Systems - Gaseous Waste Disposal - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Orifice	RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
Piping, piping components	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Valve body	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A

Table 3.3.2-27 Plant-Specific Notes: None

Table 3.3.2-28 Auxiliary Systems - Liquid & Solid Waste (Radioactive) - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Demineralizer shell	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Evaporator shell	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Filter housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Flow element	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Heat exchanger (blowdown - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	C
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	C

Table 3.3.2-28 Auxiliary Systems - Liquid & Solid Waste (Radioactive) - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (blowdown - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (blowdown - tube and tubesheet)	PB	Stainless steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	C
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	C
Heat exchanger (evaporator bottoms cooler - channel)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Heat exchanger (evaporator bottoms cooler - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (evaporator distillate - channel)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Heat exchanger (evaporator distillate - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A

Table 3.3.2-28 Auxiliary Systems - Liquid & Solid Waste (Radioactive) - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (evaporator distillate - tube and tubesheet)	PB	Stainless steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Heat exchanger (evaporator distillate condenser - channel)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
Heat exchanger (evaporator distillate condenser - shell)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
Heat exchanger (evaporator distillate condenser - tube and tubesheet)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
Heat exchanger (evaporator reboiler - channel)	LB	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-276	3.3.1-095	A
Heat exchanger (evaporator reboiler - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	A
Heat exchanger (evaporator sample cooler - outer tube)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F3.AP-203	3.3.1-046	A

Table 3.3.2-28 Auxiliary Systems - Liquid & Solid Waste (Radioactive) - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (seal cooling - shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-275	3.3.1-095	A
Heater housing (bottoms cooler preheater)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Piping, piping components	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.F.SP-101	3.4.1-016	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(E) Underground	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.A-714b	3.3.1-146	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.A-775b	3.3.1-246	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
			(I) Waste water >60°C (>140°F)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-721	3.3.1-155	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-28 Auxiliary Systems - Liquid & Solid Waste (Radioactive) - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Pump casing (blowdown pump)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Pump casing (bottoms cooler circulating)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C
Pump casing (bottoms cooler)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Pump casing (contaminated drain transfer)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-28 Auxiliary Systems - Liquid & Solid Waste (Radioactive) - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (drain tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Pump casing (evaporator circulating)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Pump casing (evaporator distillate)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Pump casing (evaporator test tank)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Pump casing (resin transfer)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Strainer body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A

Table 3.3.2-28 Auxiliary Systems - Liquid & Solid Waste (Radioactive) - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (distillate accumulator)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Tank (evaporator test)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Tank (laboratory drain sump)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Tank (waste drain)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Valve body	LB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Treated water	Loss of material	Selective Leaching (B2.1.21)	VII.C2.AP-32	3.3.1-072	A
					One-Time Inspection (B2.1.20)	VIII.F.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.F.SP-101	3.4.1-016	A

Table 3.3.2-28 Auxiliary Systems - Liquid & Solid Waste (Radioactive) - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
			(I) Waste water >60°C (>140°F)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-721	3.3.1-155	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A

Table 3.3.2-28 Plant-Specific Notes: None

Table 3.3.2-29 Auxiliary Systems - Oil Separation - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
Piping, piping components	LB	Fiberglass	(E) Air – indoor uncontrolled	Cracking, blistering, loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-720	3.3.1-150	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-719	3.3.1-082	A
			(I) Waste water	Cracking, blistering, loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-551	3.3.1-175	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Pump casing (waste oil separation)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Valve body	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-272	3.3.1-095	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(E) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-411	3.3.1-135	C
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-29 Plant-Specific Notes: None

Table 3.3.2-30 Auxiliary Systems - Radioactive Waste - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Flow element	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-30 Plant-Specific Notes: None

Table 3.3.2-31 Auxiliary Systems - Sanitary Sewage - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB	Stainless steel	(E) Waste water	Cracking	Bolting Integrity (B2.1.9)	VII.I.A-426	3.3.1-145	A
				Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-423	3.3.1-142	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
Flexible hose	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C1.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Piping, piping components	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-724	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
		PVC	(E) Air – indoor uncontrolled	None	None	VII.J.AP-268	3.3.1-119	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-787d	3.3.1-253	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A

Table 3.3.2-31 Auxiliary Systems - Sanitary Sewage - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (sewage ejector)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-724	3.3.1-072	A
					External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-724	3.3.1-072	A
					External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	A
Tank (electric shop sewage waste)	LB	Polymer	(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-797a	3.3.1-263	A
			(I) Waste water	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-797b	3.3.1-263	A
Tank (service and turbine building sewage waste)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-724	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Valve body	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-724	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
		PVC	(E) Air – indoor uncontrolled	None	None	VII.J.AP-268	3.3.1-119	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-787d	3.3.1-253	A

Table 3.3.2-31 Plant-Specific Notes: None

Table 3.3.2-32 Auxiliary Systems - Vents - Gaseous - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-748	3.3.1-219	A
					Water Chemistry (B2.1.2)	VII.F2.A-748	3.3.1-219	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-567	3.3.1-170	A
					Water Chemistry (B2.1.2)	VII.F2.A-567	3.3.1-170	A
			(E) Underground	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.A-714b	3.3.1-146	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.A-775b	3.3.1-246	A
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-748	3.3.1-219	A
					Water Chemistry (B2.1.2)	VII.F2.A-748	3.3.1-219	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-567	3.3.1-170	A
					Water Chemistry (B2.1.2)	VII.F2.A-567	3.3.1-170	A

Table 3.3.2-32 Plant-Specific Notes: None

Table 3.3.2-33 Auxiliary Systems - Containment Vacuum - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Ejector (containment vacuum - chamber)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VII.F3.A-566	3.3.1-169	C
					Water Chemistry (B2.1.2)	VII.F3.A-566	3.3.1-169	C
Ejector (containment vacuum - diffuser/steam chest)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VII.F3.A-566	3.3.1-169	C
					Water Chemistry (B2.1.2)	VII.F3.A-566	3.3.1-169	C
Ejector (containment vacuum - nozzle)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	C
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F3.A-748	3.3.1-219	C
					Water Chemistry (B2.1.2)	VII.F3.A-748	3.3.1-219	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.A-567	3.3.1-170	C
					Water Chemistry (B2.1.2)	VII.F3.A-567	3.3.1-170	C
Heat exchanger (containment vacuum - channel)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	C
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F3.AP-203	3.3.1-046	A

Table 3.3.2-33 Auxiliary Systems - Containment Vacuum - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (containment vacuum - shell)	LB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	C
			(I) Treated water	Loss of material	Selective Leaching (B2.1.21)	VII.F3.AP-65	3.3.1-072	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-101	3.4.1-016	C
					Water Chemistry (B2.1.2)	VIII.A.SP-101	3.4.1-016	C
Piping, piping components	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Steam	Cumulative fatigue damage	TLAA	VII.E1.A-34	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F3.A-566	3.3.1-169	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.B1.S-15	3.4.1-005	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
Pump casing (containment vacuum)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.A.SP-101	3.4.1-016	A

Table 3.3.2-33 Auxiliary Systems - Containment Vacuum - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Sight glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Treated water	None	None	VII.J.AP-51	3.3.1-117	A
Sight glass (body)	LB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Treated water	Loss of material	Selective Leaching (B2.1.21)	VII.C2.AP-32	3.3.1-072	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.A.SP-101	3.4.1-016	A
Strainer body	LB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Treated water	Loss of material	Selective Leaching (B2.1.21)	VII.C2.AP-32	3.3.1-072	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.A.SP-101	3.4.1-016	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Tank (moisture separator)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-75	3.4.1-012	A
					Water Chemistry (B2.1.2)	VIII.E.SP-75	3.4.1-012	A

Table 3.3.2-33 Auxiliary Systems - Containment Vacuum - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A, 1
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Treated water	Loss of material	Selective Leaching (B2.1.21)	VII.C2.AP-32	3.3.1-072	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.A.SP-101	3.4.1-016	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VII.F3.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F3.A-566	3.3.1-169	A

Table 3.3.2-33 Plant-Specific Notes:

1. Cracking of copper alloy (>15% Zn) in air and condensation environments requires the presence of ammonia-based compounds. In indoor air, such compounds could be conveyed to external surfaces of components via leakage through the insulation from bolted connections. However, internal surfaces of components are not exposed to contamination from external leakage sources. Therefore, internal cracking of these components is not expected.

Table 3.3.2-34 Auxiliary Systems - Chilled Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Condensation	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
Compressor (oil reservoir)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.F2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.F2.AP-127	3.3.1-097	A
Ejector (steam chest and diffuser)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-566	3.3.1-169	C
					Water Chemistry (B2.1.2)	VII.F2.A-566	3.3.1-169	C
Ejector (steam nozzle)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-748	3.3.1-219	C
					Water Chemistry (B2.1.2)	VII.F2.A-748	3.3.1-219	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-567	3.3.1-170	C
					Water Chemistry (B2.1.2)	VII.F2.A-567	3.3.1-170	C
Expansion joint	LB	Elastomer	(I) Closed–cycle cooling water	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.AP-259	3.3.1-085	A
			(E) Condensation	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
Filter housing	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.F2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.F2.AP-127	3.3.1-097	A

Table 3.3.2-34 Auxiliary Systems - Chilled Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Flexible hose	LB;PB	Stainless steel	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
Heat exchanger (air ejector - shell)	LB	Steel	(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.S-438	3.4.1-091	A
Heat exchanger (chilled water condenser - shell)	LB	Steel	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Heat exchanger (chilled water condenser - waterbox)	LB	Steel	(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.S-438	3.4.1-091	A
Heat exchanger (mechanical chiller condenser - channel)	LB	Steel with internal coating	(I) Closed–cycle cooling water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C2.A-416	3.3.1-138	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C2.A-414	3.3.1-139	B
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Heat exchanger (mechanical chiller cooler - channel)	LB	Steel with internal coating	(I) Closed–cycle cooling water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C2.A-416	3.3.1-138	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C2.A-414	3.3.1-139	B
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A

Table 3.3.2-34 Auxiliary Systems - Chilled Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (mechanical chiller oil cooler - channel)	LB	Steel	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Heat exchanger (mechanical chiller oil cooler - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-41	3.3.1-080	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-131	3.3.1-098	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-131	3.3.1-098	A
Heat exchanger (pumpout condenser - channel)	LB	Steel with internal coating	(I) Closed–cycle cooling water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C2.A-416	3.3.1-138	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.C2.A-414	3.3.1-139	B
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Heat exchanger (RWST cooler - channel)	SI	Stainless steel	(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.I.A-734b	3.3.1-205	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.I.A-761b	3.3.1-232	C
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	C
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	C
Heat exchanger (RWST cooler - shell)	SI	Steel	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-417	3.3.1-096b	A
Orifice	LB;PB;RF	Stainless steel	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A

Table 3.3.2-34 Auxiliary Systems - Chilled Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	A
			(E) Condensation	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.C2.AP-133	3.3.1-099	A
					One-Time Inspection (B2.1.20)	VII.C2.AP-133	3.3.1-099	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.F2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.F2.AP-127	3.3.1-097	A
			(I) Steam	Cumulative fatigue damage	TLAA	VII.E1.A-34	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F2.A-566	3.3.1-169	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-284	3.3.1-109	A

Table 3.3.2-34 Auxiliary Systems - Chilled Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (central chilled water)	LB	Steel	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Pump casing (chilled water circulating)	LB	Steel	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Pump casing (chilled water condensate)	LB	Gray cast iron	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Pump casing (control & relay room chilled water)	PB	Steel	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Pump casing (mechanical chilled water circulating)	LB	Steel	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Pump casing (mechanical chiller lube oil)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.F2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.F2.AP-127	3.3.1-097	A
Sight glass	LB;PB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Closed–cycle cooling water	None	None	VII.J.AP-166	3.3.1-117	A
			(E) Condensation	None	None	VII.J.AP-97	3.3.1-117	A
			(I) Lubricating oil	None	None	VII.J.AP-15	3.3.1-117	A

Table 3.3.2-34   Auxiliary Systems - Chilled Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Sight glass (body)	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	A
			(E) Condensation	None	None	VII.J.AP-144	3.3.1-114	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.F2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.F2.AP-127	3.3.1-097	A
Steam trap	LB	Steel	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-34 Auxiliary Systems - Chilled Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Strainer body	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	A
			(E) Condensation	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-271	3.3.1-093	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.H2.A-532	3.3.1-193	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.S-436	3.4.1-089	A, 1
Strainer element	FLT	Stainless steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
Tank (chilled water flash)	LB	Steel	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Tank (chilled water surge)	LB	Steel	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Tank (HV chemical feed)	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A

Table 3.3.2-34 Auxiliary Systems - Chilled Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (HV expansion)	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.I.A-734b	3.3.1-205	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.I.A-751b	3.3.1-222	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
Tank (oil separator)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.F2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.F2.AP-127	3.3.1-097	A
Valve body	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.C2.AP-133	3.3.1-099	A
					One-Time Inspection (B2.1.20)	VII.C2.AP-133	3.3.1-099	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-271	3.3.1-093	A
		Copper alloy (>15% Zn)	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	A
					Selective Leaching (B2.1.21)	VII.C2.AP-43	3.3.1-072	A
			(E) Condensation	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-454	3.4.1-106	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A

Table 3.3.2-34 Auxiliary Systems - Chilled Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.F2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.F2.AP-127	3.3.1-097	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.H2.A-532	3.3.1-193	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.S-436	3.4.1-089	A, 1
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F2.A-566	3.3.1-169	A

Table 3.3.2-34 Plant-Specific Notes:

1. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.

Table 3.3.2-35 Auxiliary Systems - Heating & Ventilation - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Air handling unit (fin)	HT	Aluminum	(E) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.F1.A-788a	3.3.1-254	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-771a	3.3.1-242	A
				Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-419	3.3.1-096a	C
Air handling unit (header)	PB	Gray cast iron	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-189	3.3.1-046	A
					Selective Leaching (B2.1.21)	VII.F3.A-50	3.3.1-072	C
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F1.A-417	3.3.1-096b	A
Air handling unit (housing)	LB;PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-26	3.3.1-055	C
Air handling unit (tube)	HT;PB	Copper alloy	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-205	3.3.1-050	A
			(E) Condensation	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-565	3.3.1-161	A
Bolting	LB;PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material; cracking; loss of preload	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-794	3.3.1-260	A, 2
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Condensation	Loss of material; cracking; loss of preload	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F2.A-794	3.3.1-260	A, 2
Compressor body (control room chiller)	PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	C

Table 3.3.2-35 Auxiliary Systems - Heating & Ventilation - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Damper housing	PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Ducting	PB;SI	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Air – indoor uncontrolled	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-504	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.AP-103	3.3.1-096	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Expansion joint	PB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Air – indoor uncontrolled	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-504	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.AP-103	3.3.1-096	A
Fan housing (Appendix R)	PB	Steel	(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-35 Auxiliary Systems - Heating & Ventilation - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Fan housing (Auxiliary Building exhaust - central)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Fan housing (Auxiliary Building exhaust - general)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Fan housing (auxiliary feed pump room exhaust)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
Fan housing (battery room exhaust)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
Fan housing (chiller room exhaust)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
Fan housing (control room emergency supply)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
Fan housing (Intake Structure exhaust)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C

Table 3.3.2-35 Auxiliary Systems - Heating & Ventilation - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Fan housing (motor control center)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
Fan housing (safeguards area exhaust)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Fan housing (safeguards area)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
Fan housing (service water pump house exhaust)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
Filter housing (Auxiliary Building exhaust)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Filter housing (containment purge supply vent)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C

Table 3.3.2-35 Auxiliary Systems - Heating & Ventilation - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Filter housing (control room emergency supply)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
Filter housing (refrigerant)	PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	A
Filter housing (relay room emergency supply)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
Heat exchanger (central area chiller condenser - channel)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-41	3.3.1-080	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Heat exchanger (central area chiller evaporator - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-41	3.3.1-080	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-189	3.3.1-046	A
Heat exchanger (containment cooling - fin)	HT	Copper alloy	(E) Air – indoor uncontrolled	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-419	3.3.1-096a	C

Table 3.3.2-35 Auxiliary Systems - Heating & Ventilation - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (containment cooling - header)	PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
Heat exchanger (containment cooling - tube)	HT;PB	Copper alloy	(E) Air – indoor uncontrolled	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-419	3.3.1-096a	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-205	3.3.1-050	A
Heat exchanger (control room chiller condenser - channel)	PB	Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-41	3.3.1-080	A
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.F1.A-416	3.3.1-138	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.F1.A-414	3.3.1-139	B
Heat exchanger (control room chiller condenser - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-41	3.3.1-080	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	C
Heat exchanger (control room chiller condenser - tube)	HT;PB	Copper alloy	(E) Gas	None	None	VII.J.AP-9	3.3.1-114	C
			(I) Raw water	Loss of material; flow blockage	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-179	3.3.1-038	B
				Reduction of heat transfer	Open-Cycle Cooling Water System (B2.1.11)	VII.C1.AP-187	3.3.1-042	B
Heat exchanger (control room chiller condenser - tubesheet)	PB	Steel with internal coating	(E) Gas	None	None	VII.J.AP-6	3.3.1-121	C
			(I) Raw water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.F1.A-416	3.3.1-138	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.F1.A-414	3.3.1-139	B

Table 3.3.2-35 Auxiliary Systems - Heating & Ventilation - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (control room chiller evaporator - channel)	PB	Steel	(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F1.A-417	3.3.1-096b	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	C
Heat exchanger (control room chiller evaporator - shell)	PB	Steel	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-189	3.3.1-046	A
			(E) Condensation	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.F1.A-417	3.3.1-096b	A
Heat exchanger (control room chiller evaporator - tube)	HT;PB	Copper alloy	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-205	3.3.1-050	A
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	C
Heat exchanger (control room chiller evaporator - tubesheet)	PB	Steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-189	3.3.1-046	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	C
Heat exchanger (CRDM cooling - fin)	HT	Copper alloy	(E) Air – indoor uncontrolled	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-419	3.3.1-096a	C
Heat exchanger (CRDM cooling - header)	PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
Heat exchanger (CRDM cooling - tube)	HT;PB	Copper alloy	(E) Air – indoor uncontrolled	Reduction of heat transfer	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-419	3.3.1-096a	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-203	3.3.1-046	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.F1.AP-205	3.3.1-050	A

Table 3.3.2-35 Auxiliary Systems - Heating & Ventilation - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heater (ventilation unit header)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Steam	Cumulative fatigue damage	TLAA	VII.E1.A-100	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-566	3.3.1-169	C
					Water Chemistry (B2.1.2)	VII.F1.A-566	3.3.1-169	C
Heating coil (ventilation unit heater)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-566	3.3.1-169	C
					Water Chemistry (B2.1.2)	VII.F1.A-566	3.3.1-169	C
Moisture separator (control room emergency supply)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A
Moisture separator (relay room emergency supply)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A

Table 3.3.2-35 Auxiliary Systems - Heating & Ventilation - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-133	3.3.1-099	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-133	3.3.1-099	A
		Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Air – indoor uncontrolled	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-504	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.AP-103	3.3.1-096	A
Piping, piping components	LB;PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-26	3.3.1-055	A
			(I) Steam	Cumulative fatigue damage	TLAA	VII.E1.A-34	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F1.A-566	3.3.1-169	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.B1.S-15	3.4.1-005	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E1.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
Pump casing (condensate return)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.A.SP-101	3.4.1-016	A

Table 3.3.2-35 Auxiliary Systems - Heating & Ventilation - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (condensate)	LB	Polymer	(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-797a	3.3.1-263	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-797b	3.3.1-263	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Rupture plug	PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	A
Sight glass	LB;PB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Gas	None	None	VII.J.AP-98	3.3.1-117	A
			(I) Treated water	None	None	VII.J.AP-51	3.3.1-117	A
Sight glass (body)	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E1.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
Strainer body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F1.A-566	3.3.1-169	A

Table 3.3.2-35 Auxiliary Systems - Heating & Ventilation - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (condensate)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E1.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-75	3.4.1-012	A
					Water Chemistry (B2.1.2)	VIII.E.SP-75	3.4.1-012	A
Trap body	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F1.A-566	3.3.1-169	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F1.A-566	3.3.1-169	A

Table 3.3.2-35 Auxiliary Systems - Heating & Ventilation - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F1.A-566	3.3.1-169	A
		Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-454	3.4.1-106	A
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A, 1
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-133	3.3.1-099	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-133	3.3.1-099	A

Table 3.3.2-35 Auxiliary Systems - Heating & Ventilation - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VII.F1.A-748	3.3.1-219	A
					Water Chemistry (B2.1.2)	VII.F1.A-748	3.3.1-219	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-567	3.3.1-170	A
					Water Chemistry (B2.1.2)	VII.F1.A-567	3.3.1-170	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F1.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VII.F1.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F1.A-566	3.3.1-169	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E1.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A

Table 3.3.2-35 Plant-Specific Notes:

1. Cracking of copper alloy (>15% Zn) in air and condensation environments requires the presence of ammonia-based compounds. In indoor air, such compounds could be conveyed to external surfaces of components via leakage through the insulation from bolted connections. However, internal surfaces of components are not exposed to contamination from external leakage sources. Therefore, internal cracking of these components is not expected.

2. Cracking is not applicable for steel bolting in air-indoor uncontrolled or condensation environments.

Table 3.3.2-36 Auxiliary Systems - High Radiation Sampling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Flexible hose	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Fume hood	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Heat exchanger (sample cooler - shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	C
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	C

Table 3.3.2-36 Auxiliary Systems - High Radiation Sampling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	A
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
Pump casing (containment sump sample)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Pump casing (waste)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-36 Auxiliary Systems - High Radiation Sampling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (sample flask)	LB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Waste water	None	None	VII.J.AP-277	3.3.1-119	A
Tank (waste)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.E1.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Treated borated water	Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated borated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VII.E1.A-103	3.3.1-124	A
					Water Chemistry (B2.1.2)	VII.E1.A-103	3.3.1-124	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.E1.AP-79	3.3.1-125	A
					Water Chemistry (B2.1.2)	VII.E1.AP-79	3.3.1-125	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A

Table 3.3.2-36 Plant-Specific Notes: None

Table 3.3.2-37 Auxiliary Systems - Post-Accident Hydrogen Removal - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Blower housing (containment atmosphere purge)	SI	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Bolting	PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Flexible hose	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
Piping, piping components	PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Gas	None	None	VII.J.AP-22	3.3.1-120	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A

Table 3.3.2-37 Auxiliary Systems - Post-Accident Hydrogen Removal - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	PB;SI	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.AP-221a	3.3.1-006	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A

Table 3.3.2-37 Plant-Specific Notes: None

Table 3.3.2-38 Auxiliary Systems - Radiation Monitoring - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	PB;SI	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Piping, piping components	PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
Valve body	PB;SI	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.AP-221a	3.3.1-006	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F3.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A

Table 3.3.2-38 Plant-Specific Notes: None

Table 3.3.2-39 Auxiliary Systems - Alternate AC - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air – outdoor	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
Expansion joint	PB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Air – indoor uncontrolled	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-504	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.AP-103	3.3.1-096	A
			(I) Closed–cycle cooling water	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.AP-259	3.3.1-085	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Diesel exhaust	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-128	3.3.1-083	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-104	3.3.1-088	A
Filter element (vent screen)	FLT	Stainless steel	(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A, 2
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A, 2

Table 3.3.2-39 Auxiliary Systems - Alternate AC - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Filter housing	PB	Copper alloy (>15% Zn)	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
		Gray cast iron	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-778	3.3.1-249	C
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A
Filter housing (head)	PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-133	3.3.1-099	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-133	3.3.1-099	A

Table 3.3.2-39 Auxiliary Systems - Alternate AC - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Flexible hose	PB	Elastomer	(I) Air – dry	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-504	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.AP-103	3.3.1-096	A
			(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Closed–cycle cooling water	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.AP-259	3.3.1-085	A
			(I) Condensation	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-504	3.3.1-085	A
			(I) Fuel oil	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H1.A-660	3.3.1-085	A
			(I) Lubricating oil	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.A-677	3.3.1-085	A
		Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Closed–cycle cooling water >60°C (>140°F)	Cracking	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-186	3.3.1-043	A
				Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
Heat exchanger (cooling water radiators - fin)	HT	Aluminum	(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	VII.F4.A-788a	3.3.1-254	A, 1
				Loss of material	One-Time Inspection (B2.1.20)	VII.F4.A-771a	3.3.1-242	A, 1
				Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-716	3.3.1-151	C, 1

Table 3.3.2-39 Auxiliary Systems - Alternate AC - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (cooling water radiators - header)	PB	Steel	(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (cooling water radiators - tube)	HT;PB	Steel	(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
				Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-716	3.3.1-151	A, 1
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.F4.AP-204	3.3.1-050	A
Heat exchanger (fuel oil radiator - fin)	HT	Aluminum	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F4.A-788a	3.3.1-254	A, 1
				Loss of material	One-Time Inspection (B2.1.20)	VII.F4.A-771a	3.3.1-242	A, 1
				Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-716	3.3.1-151	C, 1
Heat exchanger (fuel oil radiator - header)	PB	Steel	(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
Heat exchanger (fuel oil radiator - tube)	HT;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
				Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-716	3.3.1-151	A, 1
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
				Reduction of heat transfer	Fuel Oil Chemistry (B2.1.18)	VII.H2.A-800	3.3.1-266	B
Heat exchanger (lube oil - channel)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-131	3.3.1-098	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-131	3.3.1-098	A
Heat exchanger (lube oil - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A

Table 3.3.2-39 Auxiliary Systems - Alternate AC - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (lube oil - tube)	HT;PB	Copper alloy	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-199	3.3.1-046	C
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-205	3.3.1-050	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-133	3.3.1-099	C
					One-Time Inspection (B2.1.20)	VII.H2.AP-133	3.3.1-099	C
				Reduction of heat transfer	Lubricating Oil Analysis (B2.1.26)	VII.H2.A-791	3.3.1-257	A
					One-Time Inspection (B2.1.20)	VII.H2.A-791	3.3.1-257	A
Heat exchanger (lube oil - tubesheet)	PB	Steel	(E) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-131	3.3.1-098	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-131	3.3.1-098	A
Heater housing (jacket water)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heater housing (lube oil)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-131	3.3.1-098	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-131	3.3.1-098	A
Lubricator body	PB	Copper alloy (>15% Zn)	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
Orifice	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water >60°C (>140°F)	Cracking	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-186	3.3.1-043	A
				Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A

Table 3.3.2-39 Auxiliary Systems - Alternate AC - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	PB	Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-138	3.3.1-100	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.A-26	3.3.1-055	A
			(I) Diesel exhaust	Cumulative fatigue damage	TLAA	VII.E1.A-34	3.3.1-002	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-104	3.3.1-088	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A
Pump casing (fuel transfer)	PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H1.AP-105a	3.3.1-070	B
Pump casing (jacket water)	PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	A

Table 3.3.2-39 Auxiliary Systems - Alternate AC - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (lube oil)	PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A
Sight glass	PB	Glass	(E) Air – outdoor	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Closed–cycle cooling water	None	None	VII.J.AP-166	3.3.1-117	A
Sight glass (body)	PB	Copper alloy (>15% Zn)	(E) Air – outdoor	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	A
					Selective Leaching (B2.1.21)	VII.C2.AP-43	3.3.1-072	A
Silencer	PB	Steel	(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Diesel exhaust	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-104	3.3.1-088	A
Tank (cooling water expansion)	PB	Steel	(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
Tank (fuel oil)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
Tank (fuel rack shutoff air)	PB	Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-39 Auxiliary Systems - Alternate AC - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (start air receiver)	PB	Steel with internal coating	(I) Air – dry	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	None	None	G, 3
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	None	None	G, 3
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Valve body	PB	Aluminum	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.A-451a	3.3.1-189	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.A-763a	3.3.1-234	A
		Copper alloy (>15% Zn)	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(E) Air – outdoor	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	A
					Selective Leaching (B2.1.21)	VII.C2.AP-43	3.3.1-072	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-132	3.3.1-069	B
					One-Time Inspection (B2.1.20)	VII.H2.AP-132	3.3.1-069	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-133	3.3.1-099	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-133	3.3.1-099	A
		Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A

Table 3.3.2-39 Auxiliary Systems - Alternate AC - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	PB	Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-136	3.3.1-071	B
					One-Time Inspection (B2.1.20)	VII.H2.AP-136	3.3.1-071	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-138	3.3.1-100	A
		Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(I) Diesel exhaust	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-104	3.3.1-088	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B

Table 3.3.2-39 Plant-Specific Notes:

1. External visual inspections of fins and finned tubes will identify fouling, corrosion product buildup or missing fins.
2. The fuel oil tank vent screen functions to exclude insects such as wasps from building nests within the vent pipe. As such, it prevents fuel contamination and flow blockage by remaining intact.
3. Internal epoxy coating provides barrier for internal steel surface. The Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program will manage aging of the coating.

Table 3.3.2-40 Auxiliary Systems - Emergency Diesel Generator System - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air – outdoor	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-241	3.3.1-109	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-241	3.3.1-109	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
Expansion joint	PB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Lubricating oil	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.A-677	3.3.1-085	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Diesel exhaust	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-128	3.3.1-083	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-104	3.3.1-088	A
Filter housing	LB;PB	Aluminum	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.A-451a	3.3.1-189	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.A-763a	3.3.1-234	A
			(I) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.H2.A-451a	3.3.1-189	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.A-763a	3.3.1-234	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A

Table 3.3.2-40 Auxiliary Systems - Emergency Diesel Generator System - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Flame arrestor	PB	Gray cast iron	(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-778	3.3.1-249	C
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Flexible hose	LB;PB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Lubricating oil	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.A-677	3.3.1-085	A
		Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H1.AP-136a	3.3.1-071	B
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-138	3.3.1-100	A
Heat exchanger (lubricating oil - channel)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
Heat exchanger (lubricating oil - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-131	3.3.1-098	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-131	3.3.1-098	A

Table 3.3.2-40 Auxiliary Systems - Emergency Diesel Generator System - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (lubricating oil - tube)	HT;PB	Copper alloy	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-199	3.3.1-046	A
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-205	3.3.1-050	A
			(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-133	3.3.1-099	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-133	3.3.1-099	C
				Reduction of heat transfer	Lubricating Oil Analysis (B2.1.26)	VII.H2.A-791	3.3.1-257	A
					One-Time Inspection (B2.1.20)	VII.H2.A-791	3.3.1-257	A
Heat exchanger (lubricating oil - tubesheet)	PB	Steel	(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
			(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-131	3.3.1-098	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-131	3.3.1-098	A
Heat exchanger (radiator - header)	PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	C
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	C
					Selective Leaching (B2.1.21)	VII.C2.AP-43	3.3.1-072	C
Heat exchanger (radiator - tube)	HT;PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	C
				Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-716	3.3.1-151	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	C
					Selective Leaching (B2.1.21)	VII.C2.AP-43	3.3.1-072	C
				Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-205	3.3.1-050	A
Heater housing	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-189	3.3.1-046	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A
Level gage	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A

Table 3.3.2-40 Auxiliary Systems - Emergency Diesel Generator System - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H1.AP-136a	3.3.1-071	B
Piping, piping components	LB;PB;SI	Copper alloy	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-199	3.3.1-046	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-133	3.3.1-099	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-133	3.3.1-099	A
		Elastomer with stainless steel sheath	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Lubricating oil	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.A-677	3.3.1-085	A
		Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Closed–cycle cooling water >60°C (>140°F)	Cracking	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-186	3.3.1-043	A
				Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H1.AP-136a	3.3.1-071	B
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-138	3.3.1-100	A

Table 3.3.2-40 Auxiliary Systems - Emergency Diesel Generator System - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Stainless steel	(E) Soil	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.A-425	3.3.1-144	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-137	3.3.1-107	A
		Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-778	3.3.1-249	C
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(I) Diesel exhaust	Cumulative fatigue damage	TLAA	VII.E1.A-34	3.3.1-002	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-104	3.3.1-088	A
			(E) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-284	3.3.1-109	A
Pump casing (circulation)	PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A
Pump casing (fuel oil transfer)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B

Table 3.3.2-40 Auxiliary Systems - Emergency Diesel Generator System - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (fuel oil)	PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
Pump casing (jacket water)	PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	A
Pump casing (lubricating oil)	PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A
Pump casing (pre-lube)	PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A
Rupture disc	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H1.AP-136a	3.3.1-071	B
Sight glass	PB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Fuel oil	None	None	VII.J.AP-49	3.3.1-117	A
Sight glass (body)	PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-132	3.3.1-069	B
					One-Time Inspection (B2.1.20)	VII.H2.AP-132	3.3.1-069	A

Table 3.3.2-40 Auxiliary Systems - Emergency Diesel Generator System - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Strainer body	LB;PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
		Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A
Strainer element	FLT	Stainless steel	(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-138	3.3.1-100	A
		Steel	(E) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
Tank (coolant drain)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-778	3.3.1-249	C
Tank (coolant expansion)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water >60°C (>140°F)	Cracking	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-186	3.3.1-043	A
				Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
Tank (dirty fuel)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B

Table 3.3.2-40 Auxiliary Systems - Emergency Diesel Generator System - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (fuel oil - day)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H1.AP-136a	3.3.1-071	B
Tank (fuel oil storage)	PB	Steel with internal coating	(I) Fuel oil	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.H1.A-416	3.3.1-138	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.H1.A-414	3.3.1-139	B
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
Tank (start air receiver)	PB	Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Trap body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.A-26	3.3.1-055	A
Valve body	LB;PB	Copper alloy	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.H2.AP-199	3.3.1-046	C
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-132	3.3.1-069	B
					One-Time Inspection (B2.1.20)	VII.H2.AP-132	3.3.1-069	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-133	3.3.1-099	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-133	3.3.1-099	A

Table 3.3.2-40 Auxiliary Systems - Emergency Diesel Generator System - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Copper alloy (>15% Zn)	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-199	3.3.1-046	A
					Selective Leaching (B2.1.21)	VII.C2.AP-43	3.3.1-072	A
			(I) Condensation	None	None	VII.J.AP-144	3.3.1-114	A, 1
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-132	3.3.1-069	B
					One-Time Inspection (B2.1.20)	VII.H2.AP-132	3.3.1-069	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-133	3.3.1-099	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-133	3.3.1-099	A
		Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-778	3.3.1-249	C
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
					Selective Leaching (B2.1.21)	VII.C2.A-50	3.3.1-072	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A
		Polymer	(I) Air – dry	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.A-797b	3.3.1-263	A
			(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-797a	3.3.1-263	A

Table 3.3.2-40 Auxiliary Systems - Emergency Diesel Generator System - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.A-52	3.3.1-049	A
			(I) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.H2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.H2.AP-221a	3.3.1-006	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H1.AP-136a	3.3.1-071	B
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-138	3.3.1-100	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-138	3.3.1-100	A
		Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-778	3.3.1-249	C
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(I) Diesel exhaust	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-104	3.3.1-088	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.H2.AP-127	3.3.1-097	A
					One-Time Inspection (B2.1.20)	VII.H2.AP-127	3.3.1-097	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-284	3.3.1-109	A

Table 3.3.2-40 Auxiliary Systems - Emergency Diesel Generator System - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Water separator	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.A-26	3.3.1-055	A

Table 3.3.2-40 Plant-Specific Notes:

1. Cracking of copper alloy (>15% Zn) in air and condensation environments requires the presence of ammonia-based compounds. In indoor air, such compounds could be conveyed to external surfaces of components via leakage through the insulation from bolted connections. However, internal surfaces of components within the emergency diesel generator starting air subsystem are not exposed to contamination from external leakage sources. Therefore, internal cracking of these components is not expected.

Table 3.3.2-41 Auxiliary Systems - Security - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
Damper housing	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-778	3.3.1-249	C
Duct (cooling air discharge)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-778	3.3.1-249	C
Filter housing	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
Flame arrestor	FB	Gray cast iron	(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-778	3.3.1-249	C
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-41 Auxiliary Systems - Security - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(E) Air – outdoor	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-132	3.3.1-069	B
					One-Time Inspection (B2.1.20)	VII.H2.AP-132	3.3.1-069	A
		Polymer	(I) Fuel oil	Hardening or loss of strength; loss of material; cracking or blistering; flow blockage	Fuel Oil Chemistry (B2.1.18)	None	None	G, 2
			(E) Underground	Hardening or loss of strength; loss of material; cracking or blistering	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.A-797a	3.3.1-263	E, 1
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F4.A-778	3.3.1-249	C
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.A-26	3.3.1-055	A
			(I) Diesel exhaust	Cumulative fatigue damage	TLAA	VII.E1.A-34	3.3.1-002	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-104	3.3.1-088	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
Pump casing	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
Silencer	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Diesel exhaust	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.AP-104	3.3.1-088	A

Table 3.3.2-41 Auxiliary Systems - Security - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (fuel oil - day)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
Tank (underground fuel oil storage)	PB	Fiberglass	(I) Fuel oil	Cracking; blistering; loss of material; flow blockage	Fuel Oil Chemistry (B2.1.18)	None	None	G, 3
			(E) Soil	Cracking, blistering, loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-176	3.3.1-104	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.A-462	3.3.1-177	A
Valve body	PB	Copper alloy	(E) Air – outdoor	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-132	3.3.1-069	B
					One-Time Inspection (B2.1.20)	VII.H2.AP-132	3.3.1-069	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.A-26	3.3.1-055	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B

Table 3.3.2-41 Plant-Specific Notes:

1. The Buried and Underground Piping and Tanks (B2.1.27) program will manage aging of the external surface of the below-grade Kynar® polyvinylidene fluoride (PVDF) polymer fuel oil piping.

2. Double walled underground Kynar® polyvinylidene fluoride (PVDF) fuel oil supply and return piping was installed between the fuel oil tank and the transition sump at the Security Auxiliary Power Supply Building in 2014. PVDF piping is specifically chosen for use in transporting fuel oils and is UL-971 listed. The staff previously concluded that underground PVDF fuel oil piping had no aging effects requiring management (ML093020275, NUREG-1929 section 3.3.2.3.17). The Fuel Oil Chemistry (B2.1.18) program is assigned to ensure the fluid chemistry remains compatible with the pipe material. The lines experience flow during diesel operation and are not expected to experience water separation or pooling.

3. The Fuel Oil Chemistry (B2.1.18) program will manage aging of the internal (fuel oil) surface of the double-walled, underground fiberglass security diesel fuel oil tank. The Staff previously concluded that underground fiberglass diesel fuel oil tanks had no aging effects requiring management (ML081430109, NUREG-1907 Volume 2 section 3.3.2.3.72 and section 3.0.3.2.1). The Fuel Oil Chemistry (B2.1.18) program is assigned to ensure the fluid chemistry remains compatible with the tank material by managing fuel oil impurities associated with water and microbiological organisms. Aging of the diesel fuel oil tank exposed to diesel fuel oil is not expected without exposure of the tank's internal surfaces to contaminants in the fuel oil, such as water and microbiological organisms.

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air – outdoor	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Raw water	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-423	3.3.1-142	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-241	3.3.1-109	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
Fire damper assembly	FB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material; cracking; hardening; loss of strength; shrinkage	Fire Protection (B2.1.15)	VII.G.A-789	3.3.1-255	A, 5
			(I) Air – indoor uncontrolled	Loss of material; cracking; hardening; loss of strength; shrinkage	Fire Protection (B2.1.15)	VII.G.A-789	3.3.1-255	A, 5
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Fire hydrant	PB	Ductile iron	(E) Air – indoor uncontrolled	Loss of material	Fire Water System (B2.1.16)	VII.G.A-412	3.3.1-136	D
			(E) Air – outdoor	Loss of material	Fire Water System (B2.1.16)	VII.G.AP-149	3.3.1-063	B
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-149	3.3.1-063	B
			(E) Soil	Loss of material	Selective Leaching (B2.1.21)	VII.G.A-02	3.3.1-072	A
					Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
		Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	Fire Water System (B2.1.16)	VII.G.A-412	3.3.1-136	D
			(E) Air – outdoor	Loss of material	Fire Water System (B2.1.16)	VII.G.AP-149	3.3.1-063	B
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-149	3.3.1-063	B
			(E) Soil	Loss of material	Selective Leaching (B2.1.21)	VII.G.A-02	3.3.1-072	A
					Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
Flame arrestor	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	C, 1

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Flexible hose	PB	Elastomer	(I) Air – indoor uncontrolled	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.A-504	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-76	3.3.1-096	A
			(E) Air – outdoor	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.G.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.G.AP-221a	3.3.1-006	A
			(E) Air – outdoor	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.G.AP-221a	3.3.1-006	A
Heat exchanger (carbon dioxide tank cooling coil)	PB	Copper alloy	(E) Gas	None	None	VII.J.AP-9	3.3.1-114	A
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	A
Insulation (heat traced components)	TI	Non-metallic thermal insulation	(E) Air – indoor uncontrolled	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-704	3.3.1-182	A
			(E) Air – outdoor	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-704	3.3.1-182	A
Nozzle	SP	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
		Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A, 1

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Odorizer	PB	Aluminum	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-451a	3.3.1-189	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-763a	3.3.1-234	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F2.A-451a	3.3.1-189	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-763a	3.3.1-234	A
		Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
		Steel	(I) Air – indoor uncontrolled	Loss of material	Fire Protection (B2.1.15)	VII.G.AP-150	3.3.1-058	A
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
Orifice	PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.G.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-55	3.3.1-066	B
Piping, piping components	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-132	3.3.1-069	B
					One-Time Inspection (B2.1.20)	VII.G.AP-132	3.3.1-069	A
		Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A, 7
				Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A, 7
			(I) Air – indoor uncontrolled	Cracking	Fire Water System (B2.1.16)	VII.G.A-405a	3.3.1-132	E, 7, 8
				Flow blockage	Fire Water System (B2.1.16)	VII.G.A-404	3.3.1-131	B, 7

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Ductile iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Flow blockage	Fire Water System (B2.1.16)	VII.G.A-404	3.3.1-131	B
				Loss of material	Fire Water System (B2.1.16)	VII.G.A-412	3.3.1-136	D
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
		Ductile iron with internal lining	(I) Raw water	Loss of coating or lining integrity; loss of material or cracking (for cementitious coatings/linings)	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.G.A-416	3.3.1-138	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.G.A-414	3.3.1-139	B
						VII.G.A-415	3.3.1-140	B
			(E) Soil	Loss of material	Selective Leaching (B2.1.21)	VII.G.A-02	3.3.1-072	A
					Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Flow blockage	Fire Water System (B2.1.16)	VII.G.A-404	3.3.1-131	B, 7
				Loss of material	Fire Protection (B2.1.15)	VII.G.AP-150	3.3.1-058	A, 3
					Fire Water System (B2.1.16)	VII.G.A-412	3.3.1-136	D, 7
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A, 9
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A, 9
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B, 2, 9

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Flow blockage	Fire Water System (B2.1.16)	VII.G.A-404	3.3.1-131	B, 7
				Loss of material	Fire Protection (B2.1.15)	VII.G.AP-150	3.3.1-058	A, 3
					Fire Water System (B2.1.16)	VII.G.A-412	3.3.1-136	D, 7
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A, 1
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Concrete	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
			(E) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A, 9
				Loss of material	Fire Water System (B2.1.16)	VII.G.A-400	3.3.1-127	B, 9
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B, 2, 9
Pump casing (diesel driven fire pump)	PB	Gray cast iron	(E) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
					Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (motor driven fire pump)	PB	Gray cast iron	(E) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
					Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
Pump casing (pressure maintenance)	PB	Stainless steel	(E) Raw water	Loss of material	Fire Water System (B2.1.16)	VII.G.A-55	3.3.1-066	B
			(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-55	3.3.1-066	B
Rupture disc	PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(I) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A, 4
			(E) Air – outdoor	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
Sight glass	PB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Raw water	None	None	VII.J.AP-50	3.3.1-117	A
Sight glass (body)	PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	B
Sprinkler head	SP	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(E) Air – outdoor	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Air – indoor uncontrolled	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-403	3.3.1-130	B
			(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-403	3.3.1-130	B

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Strainer body	PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	B
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
Strainer element (deluge/alarm check valve)	FLT	Copper alloy	(E) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	B
Strainer element (pump suction)	FLT	Copper alloy	(E) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	B
Strainer element (turbine building supply header)	FLT	Copper alloy	(E) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	B
Tank (17-ton carbon dioxide storage)	PB	Steel	(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Tank (6-ton carbon dioxide storage)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Tank (carbon dioxide cylinder)	PB	Steel	(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Tank (carbon dioxide delay)	PB	Steel	(I) Air – indoor uncontrolled	Loss of material	Fire Protection (B2.1.15)	VII.G.AP-150	3.3.1-058	A, 3
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (fire pump fuel oil)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-234a	3.3.1-070	B
Tank (halon cylinder)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Tank (hydropneumatic)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
Tank (nitrogen manual release)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Tank (nitrogen)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
Tank (retarding chamber)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
Valve body	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Air – indoor uncontrolled	Flow blockage	Fire Water System (B2.1.16)	VII.G.A-404	3.3.1-131	B
			(E) Air – outdoor	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-132	3.3.1-069	B
					One-Time Inspection (B2.1.20)	VII.G.AP-132	3.3.1-069	A
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	A
			(I) Raw water	Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	B, 2

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(E) Air – outdoor	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-9	3.3.1-114	A
			(I) Raw water	Cracking	Fire Water System (B2.1.16)	VII.C1.A-473b	3.3.1-160	E, 6
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-47	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.AP-197	3.3.1-064	B
		Ductile iron	(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B
			(E) Soil	Loss of material	Selective Leaching (B2.1.21)	VII.G.A-02	3.3.1-072	A
					Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
		Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.G.A-51	3.3.1-072	A
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B

Table 3.3.2-42 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Flow blockage	Fire Water System (B2.1.16)	VII.G.A-404	3.3.1-131	B
				Loss of material	Fire Protection (B2.1.15)	VII.G.AP-150	3.3.1-058	A, 3
					Fire Water System (B2.1.16)	VII.G.A-412	3.3.1-136	D
			(E) Air – outdoor	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Gas	None	None	VII.J.AP-6	3.3.1-121	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.G.A-532	3.3.1-193	A
				Loss of material	Fire Water System (B2.1.16)	VII.G.A-400	3.3.1-127	B
				Loss of material; flow blockage	Fire Water System (B2.1.16)	VII.G.A-33	3.3.1-064	B

Table 3.3.2-42 Plant-Specific Notes:

1. Internal and external environments are such that the external surface condition is representative of the internal surface condition.
2. Flow blockage is addressed by the cited NUREG-2191 item, but is not an applicable aging effect requiring management for nonsafety-related components that do not support a function of delivering downstream flow.
3. The Fire Protection (B2.1.15) program will manage loss of material for the steel Halon and carbon dioxide fire suppression piping, tanks, and valves exposed internally to air.
4. Cracking of copper alloy (>15% Zn) in air and condensation environments requires the presence of ammonia-based compounds. In indoor air, such compounds could be conveyed to external surfaces of components via leakage through the insulation from bolted connections. However, internal surfaces of components are not exposed to contamination from external leakage sources. Therefore, internal cracking of these components is not expected.
5. Cracking, hardening, loss of strength, and shrinkage are not aging effects requiring management for steel fire damper assemblies exposed to air.
6. The Fire Water System (B2.1.16) program will manage cracking of copper alloy (>15% Zn) valves exposed to raw water.
7. This row includes piping and fittings downstream from hose rack isolation valves.
8. The Fire Water System (B2.1.16) program will manage cracking of copper alloy (>15% Zn) piping, piping components exposed internally to air - indoor uncontrolled.
9. This row includes piping and fittings associated with standpipe risers.

Table 3.3.2-43 Auxiliary Systems - Containment Access - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
Filter housing	LB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.G.AP-133	3.3.1-099	A, 2
					One-Time Inspection (B2.1.20)	VII.G.AP-133	3.3.1-099	A, 2
Flexible hose	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.G.AP-127	3.3.1-097	A, 2
					One-Time Inspection (B2.1.20)	VII.G.AP-127	3.3.1-097	A, 2
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.G.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.G.AP-221a	3.3.1-006	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	C, 1
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.G.AP-127	3.3.1-097	A, 2
					One-Time Inspection (B2.1.20)	VII.G.AP-127	3.3.1-097	A, 2

Table 3.3.2-43 Auxiliary Systems - Containment Access - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (hand)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.G.AP-127	3.3.1-097	A, 2
					One-Time Inspection (B2.1.20)	VII.G.AP-127	3.3.1-097	A, 2
Pump casing (hydraulic - electric)	LB	Aluminum	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.F3.A-451a	3.3.1-189	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.F3.A-763a	3.3.1-234	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.G.AP-162	3.3.1-099	A, 2
					One-Time Inspection (B2.1.20)	VII.G.AP-162	3.3.1-099	A, 2
Tank (oil reservoir)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.G.AP-127	3.3.1-097	A, 2
					One-Time Inspection (B2.1.20)	VII.G.AP-127	3.3.1-097	A, 2
Valve body	LB;PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405a	3.3.1-132	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.AP-66	3.3.1-009	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.G.AP-133	3.3.1-099	A, 2
					One-Time Inspection (B2.1.20)	VII.G.AP-133	3.3.1-099	A, 2
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.G.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.G.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.G.AP-221a	3.3.1-006	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.G.AP-138	3.3.1-100	A, 2
					One-Time Inspection (B2.1.20)	VII.G.AP-138	3.3.1-100	A, 2

Table 3.3.2-43 Auxiliary Systems - Containment Access - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	C, 1
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VII.G.AP-127	3.3.1-097	A, 2
					One-Time Inspection (B2.1.20)	VII.G.AP-127	3.3.1-097	A, 2

Table 3.3.2-43 Plant-Specific Notes:

1. Internal and external environments of airlock pressure equalization components are such that the external surface condition is representative of the internal surface condition.

2. Unax® AW hydraulic fluid is a petroleum based oil, similar to lubricating oil for aging management considerations.

Table 3.3.2-44 Auxiliary Systems - Generator Breaker Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
Filter housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Flexible hose	LB	Polymer	(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-797a	3.3.1-263	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.A-797b	3.3.1-263	A
Heat exchanger (generator breaker generator leads - channel)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	C
Heat exchanger (generator breaker generator leads - shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-80	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-80	3.4.1-085	A
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-44 Auxiliary Systems - Generator Breaker Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Pump casing (generator breaker cooling water)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Separator	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Silencer	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Tank (expansion)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-162	3.4.1-083	A
					Water Chemistry (B2.1.2)	VIII.E.SP-162	3.4.1-083	A

Table 3.3.2-44 Auxiliary Systems - Generator Breaker Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Condensation	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.3.2-44 Plant-Specific Notes: None

Table 3.3.2-45 Auxiliary Systems - Water Treatment - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-03	3.3.1-012	A
				Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(E) Waste water	Loss of preload	Bolting Integrity (B2.1.9)	VII.I.AP-124	3.3.1-015	A
				Loss of material	Bolting Integrity (B2.1.9)	VII.I.A-423	3.3.1-142	A
Demineralizer shell	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A

Table 3.3.2-45 Auxiliary Systems - Water Treatment - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Filter housing	LB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-102	3.3.1-076	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.AP-113	3.3.1-082	A
			(I) Treated water	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-75	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-76	3.3.1-096	A
		Polymer	(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-797a	3.3.1-263	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C2.A-797b	3.3.1-263	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Flash evaporator (shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A

Table 3.3.2-45 Auxiliary Systems - Water Treatment - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Flow element	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Heat exchanger (flash evaporator vent condenser - shell and channel)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	C
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	C
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Heat exchanger (Unit 1 flash evaporator distillate cooler - shell and channel)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Heat exchanger (Unit 2 flash evaporator distillate cooler - channel)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Heat exchanger (Unit 2 flash evaporator distillate cooler - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	A

Table 3.3.2-45 Auxiliary Systems - Water Treatment - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Piping, piping components	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
		Fiberglass	(E) Air – indoor uncontrolled	Cracking, blistering, loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-720	3.3.1-150	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-719	3.3.1-082	A
			(I) Raw water	Cracking, blistering, loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-460	3.3.1-175	A
		PVC	(E) Air – indoor uncontrolled	None	None	VII.J.AP-268	3.3.1-119	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-797b	3.3.1-263	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-45 Auxiliary Systems - Water Treatment - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
			(E) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	C
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Pump casing (chemical feed slug)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
Pump casing (chemical feed)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A

Table 3.3.2-45 Auxiliary Systems - Water Treatment - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (chemistry booster pump)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Pump casing (demineralizer sump)	LB	Steel	(E) Waste water	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5.A-410	3.3.1-135	A
Pump casing (flash evaporator distillate)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Pump casing (flash evaporator makeup)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-51	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Pump casing (flash evaporator recirculation)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-51	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Pump casing (sand filter backwash)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-51	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A

Table 3.3.2-45 Auxiliary Systems - Water Treatment - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (steam generator transfer)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Pump casing (steam generator wet lay-up recirculation)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Pump casing (Unit 2 vacuum)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
Sight glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VII.J.AP-48	3.3.1-117	A
			(I) Raw water	None	None	VII.J.AP-50	3.3.1-117	A
			(I) Treated water	None	None	VII.J.AP-51	3.3.1-117	A
Sight glass (body)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A

Table 3.3.2-45 Auxiliary Systems - Water Treatment - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Strainer body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
Tank (air-water separation)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-078	A
Tank (chemical addition)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.4.1-014	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Tank (chemical feed)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Tank (chemistry lab demineralized water storage)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
Tank (dilution water head)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A

Table 3.3.2-45 Auxiliary Systems - Water Treatment - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (measure)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Valve body	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VII.J.AP-144	3.3.1-114	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A

Table 3.3.2-45 Auxiliary Systems - Water Treatment - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.C1.A-51	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VII.C2.AP-209a	3.3.1-004	A
				Loss of material	One-Time Inspection (B2.1.20)	VII.C2.AP-221a	3.3.1-006	A
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.F2.A-778	3.3.1-249	C
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VII.I.A-79	3.3.1-009	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C1.A-532	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.C1.A-727	3.3.1-134	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.C2.A-439	3.3.1-193	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A

Table 3.3.2-45 Plant-Specific Notes: None

Tables 3.3.2-1 through 3.3.2-45 Industry Standard Notes:

A. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

B. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.

C. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

D. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to the NUREG-2191 AMP.

E. Consistent with NUREG-2191 item for 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.

G. Environment not in NUREG-2191 for this component and material.

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.

J. Neither the component nor the material and environment combination is evaluated in NUREG-2191.

3.4 AGING MANAGEMENT OF STEAM AND POWER CONVERSION SYSTEMS

3.4.1 INTRODUCTION

This section provides the results of the aging management review for those components identified in Section 2.3.4, Steam and Power Conversion Systems, as being subject to aging management review. The systems, or portions of systems, which are addressed in this section are described in the indicated sections.

- Steam and Power Conversion Systems (Section 2.3.4)
- Main Steam (Section 2.3.4.1)
- Auxiliary Boilers (Section 2.3.4.2)
- Extraction Steam (Section 2.3.4.3)
- Auxiliary Steam (Section 2.3.4.4)
- Feedwater (Section 2.3.4.5)
- Condensate (Section 2.3.4.6)
- Condensate Polishing (Section 2.3.4.7)
- Steam Drains (Section 2.3.4.8)
- Blowdown (Section 2.3.4.9)
- Lubricating Oil (Section 2.3.4.10)
- Main Generator Seal Oil (Section 2.3.4.11)
- Electro-Hydraulic Control (Section 2.3.4.12)

3.4.2 RESULTS

The following tables summarize the results of the aging management review for Steam and Power Conversion Systems.

- Table 3.4.2-1, Steam and Power Conversion System - Main Steam - Aging Management Evaluation
- Table 3.4.2-2, Steam and Power Conversion System - Auxiliary Boilers - Aging Management Evaluation
- Table 3.4.2-3, Steam and Power Conversion System - Extraction Steam - Aging Management Evaluation
- Table 3.4.2-4, Steam and Power Conversion System - Auxiliary Steam - Aging Management Evaluation
- Table 3.4.2-5, Steam and Power Conversion System - Feedwater - Aging Management Evaluation
- Table 3.4.2-6, Steam and Power Conversion System - Condensate - Aging Management Evaluation
- Table 3.4.2-7, Steam and Power Conversion System - Condensate Polishing - Aging Management Evaluation
- Table 3.4.2-8, Steam and Power Conversion System - Steam Drains - Aging Management Evaluation
- Table 3.4.2-9, Steam and Power Conversion System - Blowdown - Aging Management Evaluation
- Table 3.4.2-10, Steam and Power Conversion System - Lubricating Oil - Aging Management Evaluation
- Table 3.4.2-11, Steam and Power Conversion System - Main Generator Seal Oil - Aging Management Evaluation
- Table 3.4.2-12, Steam and Power Conversion System - Electro-Hydraulic Control - 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 system component types are:

- Copper alloy (>15% Zn)
- Nickel alloy
- Non-metallic thermal insulation
- Stainless steel
- Steel

Environment

The main steam system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air with borated water leakage
- Steam
- Treated water
- Underground

Aging Effects Requiring Management

The following aging effects, associated with the main steam system, require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of material
- Loss of preload
- Reduced thermal insulation resistance
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the main steam system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.27)
- Compressed Air Monitoring (B2.1.14)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.4.2.1.2 Auxiliary Boilers

Materials

The materials of construction for the auxiliary boilers system component types are:

- Copper alloy
- Copper alloy (>15% Zn)
- Glass
- Gray cast iron
- Stainless steel
- Steel

Environment

The auxiliary boilers system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Fuel oil
- Steam
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the auxiliary boilers system, require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the auxiliary boilers system component types:

- Bolting Integrity (B2.1.9)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Fuel Oil Chemistry (B2.1.18)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.4.2.1.3 Extraction Steam

Materials

The materials of construction for the extraction steam system component types are:

- Stainless steel
- Steel

Environment

The extraction steam system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Condensation
- Steam
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the extraction steam system, require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the extraction steam system component types:

- Bolting Integrity (B2.1.9)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.4.2.1.4 Auxiliary Steam

Materials

The materials of construction for the auxiliary steam system component types are:

- Gray cast iron
- Stainless steel
- Steel

Environment

The auxiliary steam system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Steam
- Treated water

Aging Effects Requiring Management

The following aging effects, associated with the auxiliary steam system, require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the auxiliary steam system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.4.2.1.5 Feedwater

Materials

The materials of construction for the feedwater system component types are:

- Copper alloy
- Elastomer
- Glass
- Non-metallic thermal insulation
- Polymer
- Stainless steel
- Steel

Environment

The feedwater system component types are exposed to the following environments:

- Air – dry
- Air – indoor uncontrolled
- Air with borated water leakage
- Lubricating oil
- Raw water
- Steam
- Treated water
- Treated water >60°C (>140°F)
- Underground

Aging Effects Requiring Management

The following aging effects, associated with the feedwater system, require management:

- Cracking
- Cracking or blistering
- Cumulative fatigue damage
- Flow blockage
- Hardening or loss of strength
- Long-term loss of material
- Loss of material
- Loss of preload
- Reduced thermal insulation resistance
- Reduction of heat transfer
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the feedwater system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.27)
- Compressed Air Monitoring (B2.1.14)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Water Chemistry (B2.1.2)

3.4.2.1.6 Condensate

Materials

The materials of construction for the condensate system component types are:

- Copper alloy
- Copper alloy (>15% Zn)
- Elastomer
- Glass
- Gray cast iron
- Stainless steel
- Steel
- Steel with internal coating

Environment

The condensate system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Concrete
- Steam
- Treated water
- Treated water >60°C (>140°F)
- Underground

Aging Effects Requiring Management

The following aging effects, associated with the condensate system, require management:

- Cracking
- Cumulative fatigue damage
- Hardening or loss of strength
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the condensate system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.27)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- One-Time Inspection (B2.1.20)
- Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.4.2.1.7 Condensate Polishing

Materials

The materials of construction for the condensate polishing system component types are:

- Ductile iron
- Glass
- Polymer
- Stainless steel
- Steel
- Steel with internal coating

Environment

The condensate polishing system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Closed–cycle cooling water
- Treated water
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the condensate polishing system, require management:

- Cracking
- Cracking or blistering
- Hardening or loss of strength
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the condensate polishing system component types:

- Bolting Integrity (B2.1.9)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.4.2.1.8 Steam Drains

Materials

The materials of construction for the steam drains system component types are:

- Copper alloy
- Copper alloy (>15% Zn)
- Glass
- Stainless steel
- Steel

Environment

The steam drains system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Lubricating oil
- Raw water
- Steam
- Treated water
- Treated water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects, associated with the steam drains system, require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the steam drains system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.4.2.1.9 Blowdown

Materials

The materials of construction for the blowdown system component types are:

- Copper alloy (>15% Zn)
- Glass
- Non-metallic thermal insulation
- Stainless steel
- Steel

Environment

The blowdown system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Air with borated water leakage
- Closed–cycle cooling water
- Steam
- Treated water
- Treated water >60°C (>140°F)
- Underground

Aging Effects Requiring Management

The following aging effects, associated with the blowdown system, require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of material
- Loss of preload
- Reduced thermal insulation resistance
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the blowdown system component types:

- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Buried and Underground Piping and Tanks (B2.1.27)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Flow-Accelerated Corrosion (B2.1.8)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Water Chemistry (B2.1.2)

3.4.2.1.10 Lubricating Oil

Materials

The materials of construction for the lubricating oil system component types are:

- Copper alloy
- Copper alloy (>15% Zn)
- Glass
- Gray cast iron
- Stainless steel
- Steel
- Steel with internal coating

Environment

The lubricating oil system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Lubricating oil
- Raw water
- Waste water

Aging Effects Requiring Management

The following aging effects, associated with the lubricating oil system, require management:

- Cracking
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the lubricating oil system component types:

- Bolting Integrity (B2.1.9)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)

3.4.2.1.11 Main Generator Seal Oil

Materials

The materials of construction for the main generator seal oil system component types are:

- Copper alloy
- Glass
- Gray cast iron
- Stainless steel
- Steel

Environment

The main generator seal oil system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Condensation
- Gas
- Lubricating oil
- Raw water

Aging Effects Requiring Management

The following aging effects, associated with the main generator seal oil system, require management:

- Cracking
- Long-term loss of material
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the main generator seal oil system component types:

- Bolting Integrity (B2.1.9)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)

3.4.2.1.12 Electro-Hydraulic Control

Materials

The materials of construction for the electro-hydraulic control system component types are:

- Gray cast iron
- Stainless steel
- Steel

Environment

The electro-hydraulic control system component types are exposed to the following environments:

- Air – indoor uncontrolled
- Gas
- Lubricating oil
- Raw water

Aging Effects Requiring Management

The following aging effects, associated with the electro-hydraulic control system, require management:

- Cracking
- Long-term loss of material
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the electro-hydraulic control system component types:

- Bolting Integrity (B2.1.9)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Lubricating Oil Analysis (B2.1.26)
- One-Time Inspection (B2.1.20)

3.4.2.2 Further Evaluation of Aging Management as Recommended by NUREG-2192

NUREG-2192 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the License Renewal Application. For the steam and power conversion system, those evaluations are addressed in the following sections.

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.

[3.4.1-001] - Fatigue of Steam and Power Conversion Systems components is a time-limited aging analysis (TLAA), as defined in 10 CFR 54.3. The evaluation of this TLAA is addressed in Section 4.3.3, Metal Fatigue – ANSI B31.1.

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 atmospheric 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.

A review of NAPS operating experience identified cracking of stainless steel piping in a valve pit and in a pipe tunnel in which groundwater inleakage to the areas wetted the piping with contaminants that supported stress corrosion cracking. The external environment in these below-grade areas where groundwater inleakage may wet components is called "underground" in the SLRA. The operating experience review did not identify cracking of stainless steel components in other air environments (air-indoor uncontrolled, air-outdoor, or condensation). Cracking of stainless steel components in an underground environment will be managed by the Buried and Underground Piping and Tanks (B2.1.27) program. The absence of the aging effect in other air environments will be confirmed by the One-Time Inspection (B2.1.20) program.

[3.4.1-002] – Cracking of stainless steel components exposed to air-indoor uncontrolled and condensation is managed by the One-Time Inspection (B2.1.20) program.

[3.4.1-074] – Cracking of stainless steel underground components is managed by the Buried and Underground Piping and Tanks (B2.1.27) program.

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 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 atmospheric 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 NAPS operating experience identified cracking of stainless steel piping in a valve pit and in a pipe tunnel in which groundwater inleakage to the areas wetted the piping with contaminants that supported stress corrosion cracking. Surface discoloration was also noted that may represent loss of material. The external environment in these below-grade areas where groundwater inleakage may wet components is called “underground” in the SLRA. Loss of material of stainless steel in underground environments requires aging management because the same contaminants that support cracking of stainless steel also support loss of material. The operating experience review did not identify loss of material due to pitting or crevice corrosion for stainless steel or nickel alloy piping, piping components, or tanks in other air environments (air-indoor uncontrolled, air-outdoor, or condensation). Loss of material for stainless steel components in an underground environment will be managed by the Buried and Underground Piping and Tanks (B2.1.27) program. The absence of the aging effect in other air environments will be confirmed by the One-Time Inspection (B2.1.20) program.

[3.4.1-003] – Loss of material of stainless steel and nickel alloy components exposed to air-indoor uncontrolled and condensation is managed by the One-Time Inspection (B2.1.20) program.

[3.4.1-095] – Loss of material of stainless steel underground components in the Steam and Power Conversion System is managed by the Buried and Underground Piping and Tanks (B2.1.27) program. NAPS has no in-scope nickel alloy underground components in the Steam and Power Conversion System.

3.4.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

Quality Assurance provisions applicable to subsequent license renewal are discussed in Appendix B1.3, Quality Assurance Program and Administrative Controls.

3.4.2.2.5 Ongoing Review of Operating Experience

The operating experience process and acceptance criteria are described in Appendix B1.4, Operating Experience.

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.

Not applicable. A review of NAPS operating experience confirms that loss of material due to recurring internal corrosion is not an aging effect requiring management for metallic piping, piping components or tanks exposed to raw water or waste water in the Steam and Power Conversion Systems.

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. If a barrier coating is credited for isolating an aluminum alloy from a potentially aggressive environment, then the barrier coating is evaluated to verify that it is impervious to the plant-specific environment. 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.

Not applicable. NAPS has no in-scope aluminum components in the Steam and Power Conversion Systems.

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.

NAPS has no in-scope steel piping components exposed to concrete in the Steam and Power Conversion System and has no in-scope stainless steel piping components exposed to concrete that is not exposed to groundwater in the Steam and Power Conversion Systems.

Loss of material and cracking can occur for stainless steel piping components with an external environment of concrete that are potentially exposed to groundwater. Embedded piping that exits concrete into soil is potentially exposed to groundwater. Loss of material and cracking for stainless steel components with an external environment of concrete that exit the concrete into soil is managed by the Buried and Underground Piping and Tanks (B2.1.27) program as identified in items [3.4.1-047] and [3.4.1-072]

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 generally 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 generally 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 atmospheric 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.

Not applicable. NAPS has no in-scope aluminum components in the Steam and Power Conversion Systems.

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Results Tables: Steam and Power Conversion Systems

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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 of steel piping, piping components exposed to any environment is a TLAA. See further evaluation 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. Cracking of stainless steel components exposed to air - indoor uncontrolled or condensation is managed by the One-Time Inspection (B2.1.20) program. See further evaluation in Section 3.4.2.2.2.
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. Loss of material of stainless steel or nickel alloy components exposed to air - indoor uncontrolled or condensation is managed by the One-Time Inspection (B2.1.20) program. See further evaluation 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.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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. In addition to Steam and Power Conversion System, components in Auxiliary Systems (primary and secondary plant gas supplies, chemical and volume control, containment vacuum, heating and ventilation, and vacuum priming) are aligned to this item.
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.
3.4.1-007	High-strength steel closure bolting exposed to air, soil, underground	Cracking due to SCC; cyclic loading	AMP XI.M18, Bolting Integrity	No	Not applicable. NAPS has no in-scope high-strength steel closure bolting exposed to air, soil, or underground in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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.
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. In addition to Steam and Power Conversion System, components in Auxiliary Systems (boron recovery and sampling system) are aligned to this item.
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. In addition to Steam and Power Conversion System, components in Auxiliary Systems (containment vacuum, heating and ventilation, and vacuum priming) are aligned to this item.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-014	Steel piping, piping components exposed to steam, treated water	Loss of material due to general, pitting, crevice corrosion, MIC (treated water only)	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191 with a different aging management program credited for some components. In addition to Steam and Power Conversion System, components in Auxiliary Systems (primary and secondary plant gas supplies, boron recovery, liquid and solid waste, water treatment, chemical and volume control, sampling system, containment vacuum, heating and ventilation, neutron shield tank cooling, and vacuum priming) are aligned to this item. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program manages loss of material of steel components exposed to treated water environments that are not managed by the Water Chemistry (B2.1.2) program (such as the environment within chemical addition components) in Auxiliary Systems (neutron shield tank cooling) and Steam and Power Conversion System (auxiliary boilers).
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. In addition to Steam and Power Conversion System, components in Auxiliary Systems (liquid and solid waste, water treatment, and sampling system) are aligned to this item.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-016	Copper alloy, aluminum piping, piping components exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion, MIC (copper alloy only)	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191 with a different aging management program credited for some components. In addition to Steam and Power Conversion System, components in Auxiliary Systems (bearing cooling, primary grade water, liquid and solid waste, sampling system, containment vacuum, service water, and heating and ventilation) are aligned to this item. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program manages loss of material of steel components exposed to treated water environments that are not managed by the Water Chemistry (B2.1.2) program (such as the environment within chemical addition components) in Auxiliary Systems (bearing cooling, and service water).
3.4.1-018	Copper alloy, stainless steel heat exchanger tubes exposed to treated water	Reduction of heat transfer due to fouling	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191. In addition to Steam and Power Conversion System, components in Engineered Safety Features (recirculation spray) are aligned to this item.
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. NAPS has no in-scope stainless steel heat exchanger components exposed to raw water in the Steam and Power Conversion System. Loss of material of steel heat exchanger components exposed to raw water is addressed in row 3.4.1-091. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope stainless steel piping, piping components exposed to raw water in the Steam and Power Conversion System. Loss of material of copper alloy components exposed to raw water is addressed in row 3.4.1-091. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Open-Cycle Cooling Water System (B2.1.11) program implementation. Only components in Auxiliary Systems (chemical and volume control) are aligned to this item.
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. NAPS has no in-scope stainless steel piping, piping components exposed to closed-cycle cooling water >60°C (>140°F) in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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	Consistent with NUREG-2191.
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. NAPS has no in-scope stainless steel heat exchanger components or piping, piping components exposed to closed-cycle cooling water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope copper alloy piping, piping components exposed to closed-cycle cooling water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope stainless steel or copper alloy heat exchanger tubes exposed to closed-cycle cooling water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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 exceptions. Exceptions apply to the NUREG-2191 recommendations for Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17) program implementation.
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. NAPS has no in-scope gray cast iron, ductile iron piping, piping components exposed to soil in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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.
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.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-035	Aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.4.2.2.9)	Not applicable. NAPS has no in-scope aluminum piping, piping components or tanks exposed to air or condensation in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
3.4.1-036	Steel piping, piping components exposed to air – outdoor	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Not applicable. NAPS has no in-scope steel piping, piping components exposed to air – outdoor in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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	Consistent with NUREG-2191.
3.4.1-038	Steel piping, piping components exposed to raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, Open-Cycle Cooling Water System	No	Not applicable. Loss of material and flow blockage of steel piping, piping components exposed to raw water is addressed in row 3.4.1-089. The associated NUREG-2191 aging items are not used.
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.
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.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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. NAPS has no in-scope aluminum piping, piping components exposed to lubricating oil in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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	Consistent with NUREG-2191.
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.
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. NAPS has no in-scope aluminum heat exchanger tubes exposed to lubricating oil in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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.
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.
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. NAPS has no in-scope nickel alloy piping, piping components, tanks or closure bolting exposed to soil or concrete in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191.
3.4.1-051	Steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.4.2.2.8)	Not applicable. NAPS has no in-scope steel piping, piping components exposed to concrete in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
3.4.1-052	Aluminum piping, piping components exposed to gas	None	None	No	Not applicable. NAPS has no in-scope aluminum piping, piping components exposed to gas in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope copper alloy, copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
3.4.1-054	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191.
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.
3.4.1-056	Nickel alloy piping, piping components exposed to air with borated water leakage	None	None	No	Not applicable. NAPS has no in-scope nickel alloy piping, piping components exposed to air with borated water leakage in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-057	PVC piping, piping components exposed to air – indoor uncontrolled, condensation	None	None	No	Not applicable. NAPS has no in-scope PVC piping, piping components exposed to air – indoor uncontrolled or condensation in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
3.4.1-058	Stainless steel piping, piping components exposed to gas	None	None	No	Consistent with NUREG-2191.
3.4.1-059	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Consistent with NUREG-2191.
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.
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. Recurring internal corrosion has not been identified by a search of NAPS operating experience for piping, piping components or tanks exposed to raw water or waste water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
3.4.1-062	Steel, stainless steel or aluminum tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to treated water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC (steel, stainless steel only)	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Not applicable. NAPS has no in-scope steel (without an internal coating), stainless steel, or aluminum tanks (within the scope of AMP XI.M29) exposed to treated water in the Steam and Power Conversion System. Loss of material of steel with internal coating tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to treated water is addressed in item 3.4.1-067. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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	Not applicable. NAPS has no in-scope insulated steel or copper alloy (>15% Zn or >8% Al), piping, piping components, tanks, or tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to external condensation in the Steam and Power Conversion System. Loss of material of steel components exposed to an external environment of air - indoor uncontrolled is addressed in row 3.4.1-034 Cracking of copper alloy (>15% Zn or >8% Al) exposed to air - indoor uncontrolled is address in row 3.4.1-106 Loss of material of tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air - indoor uncontrolled is addressed in row 3.4.1-030 The associated NUREG-2191 aging items are not used.
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.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program implementation.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program implementation.
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. NAPS has no in-scope gray cast iron or ductile iron piping, piping components with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, or waste water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope stainless steel, steel, nickel alloy, or copper alloy closure bolting exposed to lubricating oil, treated water, treated borated water, raw water, or waste water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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.
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	Not applicable. NAPS has no in-scope stainless steel closure bolting exposed to air, soil, concrete, underground, or waste water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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)	Consistent with NUREG-2191. Cracking of stainless steel underground components is managed by the Buried and Underground Piping and Tanks (B2.1.27) program. See further evaluation in Section 3.4.2.2.2
3.4.1-075	Stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes exposed to air, condensation	Reduction of heat transfer due to fouling	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Not applicable. NAPS has no in-scope stainless steel, steel, aluminum, copper alloy, or titanium heat exchanger tubes with a heat transfer function exposed to air or condensation in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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	Consistent with NUREG-2191.
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. NAPS has no in-scope elastomer piping, piping components or seals exposed to an internal environment of air or condensation in the Steam and Power Conversion System. Hardening or loss of strength of elastomer piping, piping components or seals exposed to an external environment of air - indoor uncontrolled is addressed in row 3.4.1-077 The associated NUREG-2191 aging items are not used.
3.4.1-081	Steel components exposed to treated water, raw water	Long-term loss of material due to general corrosion	AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-082	Stainless steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.4.2.2.8)	Not applicable. NAPS has no in-scope stainless steel piping components exposed to concrete that is not potentially exposed to groundwater in the Steam and Power Conversion System. Stainless steel components exposed to concrete that exit into soil are potentially exposed to groundwater, and are addressed in row 3.4.1-072 The associated NUREG-2191 aging items are not used.
3.4.1-083	Stainless steel, nickel alloy tanks exposed to treated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191 with a different aging management program credited for some components. In addition to Steam and Power Conversion System, components in Auxiliary Systems (bearing cooling and generator breaker cooling) are aligned to this item. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program manages loss of material of stainless steel components exposed to treated water that is not managed by the Water Chemistry (B2.1.2) program (such as chemical addition equipment) for Auxiliary Systems (bearing cooling).
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.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-085	Stainless steel, nickel alloy piping, piping components, PWR heat exchanger components exposed to treated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, Water Chemistry, and AMP XI.M32, One-Time Inspection	No	Consistent with NUREG-2191 with a different aging management program credited for some components.In addition to Steam and Power Conversion System, components in Auxiliary Systems (generator breaker cooling, primary grade water, drains-aerated, liquid and solid waste, radioactive waste, water treatment, chemical and volume control, bearing cooling, service water, high radiation sampling, sampling system, containment vacuum, and heating and ventilation) are aligned to this item. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program manages loss of material of stainless steel and nickel alloy components exposed to treated water that is not managed by the Water Chemistry (B2.1.2) program (such as chemical addition equipment) for Auxiliary Systems (bearing cooling, service water, and chemical and volume control) and Steam and Power Conversion System (auxiliary boilers).
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. NAPS has no in-scope stainless steel, steel, aluminum, copper alloy, or titanium heat exchanger tubes with a heat transfer function exposed to air or condensation in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. In addition to Steam and Power Conversion System, components in Auxiliary Systems (chilled water) are aligned to this item.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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. NAPS has no in-scope steel, stainless steel, or copper alloy heat exchanger tubes exposed to raw water (for components not covered by NRC GL 89-13) with a heat transfer function. The associated NUREG-2191 aging items are not used.
3.4.1-091	Steel, stainless steel, copper alloy heat exchanger components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191. In addition to Steam and Power Conversion System, components in Auxiliary Systems (chilled water) are aligned to this item.
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. NAPS has no in-scope copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope aluminum underground piping, piping components, tanks in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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)	Consistent with NUREG-2191. Loss of material of stainless steel underground components is managed by the Buried and Underground Piping and Tanks (B2.1.27) program. NAPS has no in-scope nickel alloy underground piping, piping components or tanks in the Steam and Power Conversion System. See further evaluation in Section 3.4.2.2.3
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. NAPS has no in-scope aluminum tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to soil or concrete in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope aluminum tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to air, condensation in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope stainless steel or nickel alloy tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to air or condensation in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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. NAPS has no in-scope stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil or concrete in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air or condensation in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope stainless steel tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil or concrete in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation, soil, concrete, raw water, or waste water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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)	Not applicable. Loss of material of stainless steel or nickel alloy piping, piping components and tanks exposed to air or condensation is addressed in row 3.4.1-003 The associated NUREG-2191 aging items are not used.
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)	Not applicable. Cracking of stainless steel piping, piping components and tanks exposed to air or condensation is addressed in row 3.4.1-002. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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. NAPS has no in-scope aluminum piping, piping components or tanks exposed to air or condensation in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. In addition to Steam and Power Conversion System, components in Auxiliary Systems (chilled water, primary grade water, and heating and ventilation) are aligned to this item.
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. NAPS has no in-scope copper alloy (>15% Zn or >8% Al) tanks exposed to air or condensation in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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)	Not applicable. NAPS has no in-scope aluminum piping, piping components or tanks exposed to air, condensation, raw water, or waste water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope aluminum underground piping, piping components or tanks in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope titanium heat exchanger tubes exposed to treated water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes or piping, piping components exposed to treated water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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. NAPS has no in-scope titanium heat exchanger tubes exposed to closed-cycle cooling water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope aluminum piping, piping components, tanks exposed to soil or concrete in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope aluminum piping, piping components or tanks exposed to air or condensation in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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. NAPS has no in-scope aluminum piping, piping components or tanks exposed to raw water or waste water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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	Consistent with NUREG-2191.
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. NAPS has no in-scope elastomer piping, piping components, seals exposed to an internal environment of air in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
3.4.1-124	PVC piping, piping components, tanks exposed to concrete	None	None	No	Not applicable. NAPS has no in-scope PVC piping, piping components or tanks exposed to concrete in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope PVC piping, piping components or tanks exposed to soil in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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. NAPS has no in-scope titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes or piping, piping components exposed to closed-cycle cooling water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
3.4.1-127	Aluminum piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not applicable. NAPS has no in-scope aluminum piping, piping components or tanks exposed to air with borated water leakage in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
3.4.1-128	Copper alloy piping, piping components exposed to concrete	None	None	No	Not applicable. NAPS has no in-scope copper alloy piping, piping components exposed to concrete in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope copper alloy piping, piping components exposed to soil or underground in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope titanium piping, piping components or heat exchanger components other than tubes exposed to raw water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope copper alloy (>15% Zn) piping, piping components exposed to air with borated water leakage in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-132	Stainless steel piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not applicable. 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. NAPS has no in-scope aluminum piping, piping components exposed to raw water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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. NAPS has no in-scope titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water in the Steam and Power Conversion System. The associated NUREG-2191 aging items are not used.
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	Consistent with NUREG-2191.

Results Tables: Steam and Power Conversion Systems AMR Results

Table 3.4.2-1 Steam and Power Conversion System - Main Steam - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.SP-141	3.4.1-050	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
Expansion joint	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-98	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-155	3.4.1-084	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
Flow element	PB;RF	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
Heat exchanger (moisture separator reheater - channel)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	C
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	C
Heat exchanger (moisture separator reheater - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	C
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	C

Table 3.4.2-1 Steam and Power Conversion System - Main Steam - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Insulation (containment penetration)	TI	Non-metallic thermal insulation	(E) Air – indoor uncontrolled	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-403	3.4.1-064	A
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-98	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-155	3.4.1-084	A
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-98	3.4.1-011	A
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-155	3.4.1-084	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.B1.S-408	3.4.1-060	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	V.A.E-29	3.2.1-044	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Steam	Cumulative fatigue damage	TLAA	VIII.B1.S-08	3.4.1-001	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.B1.S-15	3.4.1-005	A
						VIII.B1.S-408	3.4.1-060	A

Table 3.4.2-1 Steam and Power Conversion System - Main Steam - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Steel	(I) Treated water	Cumulative fatigue damage	TLAA	VIII.B1.S-08	3.4.1-001	A
				Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.D1.S-16	3.4.1-005	A
						VIII.D1.S-408	3.4.1-060	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.SP-161	3.4.1-050	A
Rupture disc	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-98	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-155	3.4.1-084	A
Steam chest	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	C
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	C
Strainer body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-98	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-155	3.4.1-084	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A

Table 3.4.2-1 Steam and Power Conversion System - Main Steam - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Trap body	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.SP-161	3.4.1-050	A
Turbine casing (auxiliary feed pump)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	C
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	C
Turbine casing (high pressure)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	C
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	C
Turbine casing (low pressure)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	C
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	C
Valve body	LB;PB	Copper alloy (>15% Zn)	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-454	3.4.1-106	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-98	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-155	3.4.1-084	A

Table 3.4.2-1 Steam and Power Conversion System - Main Steam - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.SP-161	3.4.1-050	A
Venturi	RF	Nickel alloy	(E) Air – indoor uncontrolled	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-157	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-157	3.4.1-084	A

Table 3.4.2-1 Plant-Specific Notes: None

Table 3.4.2-2 Steam and Power Conversion System - Auxiliary Boilers - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
Deaerator	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A, 1
				Loss of material	One-Time Inspection (B2.1.20)	VIII.C.SP-73	3.4.1-014	A, 1
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	A, 1
Expansion joint	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A, 1
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A, 1
Flexible hose	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-101	3.4.1-016	A, 1
					Water Chemistry (B2.1.2)	VIII.A.SP-101	3.4.1-016	A, 1
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-136	3.3.1-071	B
					One-Time Inspection (B2.1.20)	VII.G.AP-136	3.3.1-071	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.A.SP-98	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.A.SP-155	3.4.1-084	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A, 1
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A, 1

Table 3.4.2-2 Steam and Power Conversion System - Auxiliary Boilers - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (auxiliary boiler - steam drum)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
Heat exchanger (auxiliary boiler - wind box)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-234	3.3.1-070	B
					One-Time Inspection (B2.1.20)	VII.G.AP-234	3.3.1-070	A
Heat exchanger (auxiliary boiler fuel oil - channel)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
Heat exchanger (auxiliary boiler fuel oil - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-234	3.3.1-070	B
					One-Time Inspection (B2.1.20)	VII.G.AP-234	3.3.1-070	A
Heat exchanger (auxiliary boiler)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A, 1
				Loss of material	One-Time Inspection (B2.1.20)	VIII.C.SP-73	3.4.1-014	A, 1
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	A, 1
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-136	3.3.1-071	B
					One-Time Inspection (B2.1.20)	VII.G.AP-136	3.3.1-071	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A, 1
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A, 1
Oxygen gun	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-234	3.3.1-070	B
					One-Time Inspection (B2.1.20)	VII.G.AP-234	3.3.1-070	A

Table 3.4.2-2 Steam and Power Conversion System - Auxiliary Boilers - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-132	3.3.1-069	B
					One-Time Inspection (B2.1.20)	VII.G.AP-132	3.3.1-069	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F2.A-566	3.3.1-169	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.A.SP-98	3.4.1-011	A
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.A.SP-155	3.4.1-084	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 2
					One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A, 1
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A, 1

Table 3.4.2-2 Steam and Power Conversion System - Auxiliary Boilers - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	V.A.E-29	3.2.1-044	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-234	3.3.1-070	B
					One-Time Inspection (B2.1.20)	VII.G.AP-234	3.3.1-070	A
			(I) Steam	Cumulative fatigue damage	TLAA	VIII.B1.S-08	3.4.1-001	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.B1.S-15	3.4.1-005	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A, 1
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.C.SP-73	3.4.1-014	E, 2
					One-Time Inspection (B2.1.20)	VIII.C.SP-73	3.4.1-014	A, 1
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	A, 1
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Pump casing (ammonia feed)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.C.SP-73	3.4.1-014	E, 2
Pump casing (boiler feed)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A, 1
				Loss of material	One-Time Inspection (B2.1.20)	VIII.C.SP-73	3.4.1-014	A, 1
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	A, 1
					Selective Leaching (B2.1.21)	VIII.A.SP-27	3.4.1-033	A, 1

Table 3.4.2-2 Steam and Power Conversion System - Auxiliary Boilers - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (condensate return)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A, 1
				Loss of material	One-Time Inspection (B2.1.20)	VIII.C.SP-73	3.4.1-014	A, 1
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	A, 1
					Selective Leaching (B2.1.21)	VIII.A.SP-27	3.4.1-033	A, 1
Pump casing (fuel oil)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-234	3.3.1-070	B
					One-Time Inspection (B2.1.20)	VII.G.AP-234	3.3.1-070	A
Pump casing (hydrazine feed)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.C.SP-73	3.4.1-014	E, 2
Sight glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-33	3.4.1-055	A
			(I) Treated water	None	None	VIII.I.SP-35	3.4.1-055	A
Sight glass (body)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 2
					One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A, 1
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A, 1

Table 3.4.2-2 Steam and Power Conversion System - Auxiliary Boilers - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Strainer body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-234	3.3.1-070	B
					One-Time Inspection (B2.1.20)	VII.G.AP-234	3.3.1-070	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A, 1
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.C.SP-73	3.4.1-014	E, 2
					One-Time Inspection (B2.1.20)	VIII.C.SP-73	3.4.1-014	A, 1
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	A, 1
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Tank (ammonia feed)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.C.SP-73	3.4.1-014	E, 2
Tank (blowdown)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Tank (hydrazine feed)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.C.SP-73	3.4.1-014	E, 2
Tank (measuring)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 2

Table 3.4.2-2 Steam and Power Conversion System - Auxiliary Boilers - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (oil reservoir)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-234	3.3.1-070	B
					One-Time Inspection (B2.1.20)	VII.G.AP-234	3.3.1-070	A
Trap body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
Valve body	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-101	3.4.1-016	A, 1
					Water Chemistry (B2.1.2)	VIII.A.SP-101	3.4.1-016	A, 1
		Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-454	3.4.1-106	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-132	3.3.1-069	B
					One-Time Inspection (B2.1.20)	VII.G.AP-132	3.3.1-069	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VII.F2.A-566	3.3.1-169	A
					Water Chemistry (B2.1.2)	VII.F2.A-566	3.3.1-169	A
		Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A

Table 3.4.2-2 Steam and Power Conversion System - Auxiliary Boilers - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.A.SP-98	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.A.SP-155	3.4.1-084	A
			(I) Treated water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-87	3.4.1-085	E, 2
					One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A, 1
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A, 1
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.G.AP-234	3.3.1-070	B
					One-Time Inspection (B2.1.20)	VII.G.AP-234	3.3.1-070	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A, 1
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.C.SP-73	3.4.1-014	E, 2
					One-Time Inspection (B2.1.20)	VIII.C.SP-73	3.4.1-014	A, 1
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	A, 1
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A

Table 3.4.2-2 Plant-Specific Notes:

1. This treated water environment represents the feed supply to the auxiliary boilers and deaerator from the condensate system.
2. This treated water environment represents the ammonia and hydrazine chemical feed supply to the auxiliary boilers. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will be used instead of the Water Chemistry and One-Time Inspection programs to manage aging effects in this environment.

Table 3.4.2-3 Steam and Power Conversion System - Extraction Steam - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
Expansion joint	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.C.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.C.SP-127a	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-98	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-155	3.4.1-084	A
Piping, piping components	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.C.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.C.SP-127a	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-98	3.4.1-011	A
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-155	3.4.1-084	A

Table 3.4.2-3 Steam and Power Conversion System - Extraction Steam - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	V.A.E-29	3.2.1-044	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-60	3.4.1-037	A
			(I) Steam	Cumulative fatigue damage	TLAA	VIII.B1.S-08	3.4.1-001	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.C.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-71	3.4.1-014	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.C.S-15	3.4.1-005	A
			(I) Treated water	Cumulative fatigue damage	TLAA	VIII.B1.S-08	3.4.1-001	A
				Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.C.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.D1.S-16	3.4.1-005	A
						VIII.D1.S-408	3.4.1-060	A
Trap body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.C.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-71	3.4.1-014	A
Valve body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.C.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.C.SP-127a	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-98	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-155	3.4.1-084	A

Table 3.4.2-3 Steam and Power Conversion System - Extraction Steam - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Condensation	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.SP-60	3.4.1-037	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.C.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-71	3.4.1-014	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.C.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.C.SP-73	3.4.1-014	A

Table 3.4.2-3 Plant-Specific Notes: None

Table 3.4.2-4 Steam and Power Conversion System - Auxiliary Steam - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
Moisture separator	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-98	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-155	3.4.1-084	A
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-87	3.4.1-085	A

Table 3.4.2-4 Steam and Power Conversion System - Auxiliary Steam - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	V.A.E-29	3.2.1-044	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Steam	Cumulative fatigue damage	TLAA	VIII.B1.S-08	3.4.1-001	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.B1.S-15	3.4.1-005	A
						VIII.B1.S-408	3.4.1-060	A
			(I) Treated water	Cumulative fatigue damage	TLAA	VIII.B1.S-08	3.4.1-001	A
				Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.E.S-16	3.4.1-005	A
Pump casing (auxiliary steam drain receiver)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A
					Selective Leaching (B2.1.21)	VIII.E.SP-27	3.4.1-033	A

Table 3.4.2-4 Steam and Power Conversion System - Auxiliary Steam - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Strainer body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A
Tank (auxiliary steam drain receiver)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-75	3.4.1-012	A
					Water Chemistry (B2.1.2)	VIII.E.SP-75	3.4.1-012	A
Trap body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A

Table 3.4.2-4 Steam and Power Conversion System - Auxiliary Steam - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-98	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-155	3.4.1-084	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-74	3.4.1-014	A

Table 3.4.2-4 Plant-Specific Notes: None

Table 3.4.2-5 Steam and Power Conversion System - Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.SP-141	3.4.1-050	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
Filter housing	LB;PB;SI	Polymer	(I) Air – dry	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.D1.S-483b	3.4.1-135	A
			(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-483a	3.4.1-135	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-91	3.4.1-040	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.D1.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-74	3.4.1-014	A
Flow element	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.D1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.D1.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-74	3.4.1-014	A

Table 3.4.2-5 Steam and Power Conversion System - Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (auxiliary feedwater pump lube oil cooler - channel)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	A
Heat exchanger (auxiliary feedwater pump lube oil cooler - shell)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-76	3.4.1-041	A
					One-Time Inspection (B2.1.20)	VIII.G.SP-76	3.4.1-041	A
Heat exchanger (auxiliary feedwater pump lube oil cooler - tube)	HT;PB	Copper alloy	(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-92	3.4.1-043	C
					One-Time Inspection (B2.1.20)	VIII.G.SP-92	3.4.1-043	C
				Reduction of heat transfer	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-99	3.4.1-046	A
					One-Time Inspection (B2.1.20)	VIII.G.SP-99	3.4.1-046	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-101	3.4.1-016	C
					Water Chemistry (B2.1.2)	VIII.A.SP-101	3.4.1-016	C
				Reduction of heat transfer	One-Time Inspection (B2.1.20)	VIII.G.SP-100	3.4.1-018	A
					Water Chemistry (B2.1.2)	VIII.G.SP-100	3.4.1-018	A
Heat exchanger (auxiliary feedwater pump lube oil cooler - tubesheet)	PB	Copper alloy	(E) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-92	3.4.1-043	C
					One-Time Inspection (B2.1.20)	VIII.G.SP-92	3.4.1-043	C
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-101	3.4.1-016	C
					Water Chemistry (B2.1.2)	VIII.A.SP-101	3.4.1-016	C
Heat exchanger (first point feedwater heater - channel)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	A
Heat exchanger (first point feedwater heater - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A

Table 3.4.2-5 Steam and Power Conversion System - Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (main feed pump stuffing box jacket)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.D1.S-432	3.4.1-081	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.G.S-438	3.4.1-091	A
Heat exchanger (main feedwater pump lube oil cooler - channel)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.D1.S-432	3.4.1-081	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.G.S-438	3.4.1-091	A
Heat exchanger (main feedwater pump lube oil cooler - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-76	3.4.1-041	A
					One-Time Inspection (B2.1.20)	VIII.G.SP-76	3.4.1-041	A
Heat exchanger (main feedwater pump seal cooler - channel)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	A
Heat exchanger (main feedwater pump seal cooler - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.D1.S-432	3.4.1-081	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.G.S-438	3.4.1-091	A
Insulation (containment penetration)	TI	Non-metallic thermal insulation	(E) Air – indoor uncontrolled	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-403	3.4.1-064	A

Table 3.4.2-5 Steam and Power Conversion System - Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Orifice	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.D1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-87	3.4.1-085	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.D1.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-87	3.4.1-085	A
Piping, piping components	LB;PB;SI	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-92	3.4.1-043	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-92	3.4.1-043	A
		Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-428	3.4.1-077	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-471	3.4.1-122	A
			(I) Lubricating oil	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.H2.A-677	3.3.1-085	A
		Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.D1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-127a	3.4.1-003	A
			(I) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.D1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-127a	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-95	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-95	3.4.1-044	A

Table 3.4.2-5 Steam and Power Conversion System - Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB;SI	Stainless steel	(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-98	3.4.1-011	A
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-155	3.4.1-084	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.D1.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-88	3.4.1-011	A
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	V.A.E-29	3.2.1-044	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-91	3.4.1-040	A
			(I) Treated water	Cumulative fatigue damage	TLAA	VIII.D1.S-11	3.4.1-001	A
				Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.D1.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-74	3.4.1-014	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.D1.S-16	3.4.1-005	A
						VIII.D1.S-408	3.4.1-060	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.SP-161	3.4.1-050	A

Table 3.4.2-5 Steam and Power Conversion System - Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Positioner	SI	Polymer	(I) Air – dry	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.D1.S-483b	3.4.1-135	A
			(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-483a	3.4.1-135	C
		Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.D1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-127a	3.4.1-003	A
Pump casing (auxiliary feedwater pump oil)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-92	3.4.1-043	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-92	3.4.1-043	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.D1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-127a	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-95	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-95	3.4.1-044	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-91	3.4.1-040	A
Pump casing (main feedwater pump oil)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-91	3.4.1-040	A
Pump casing (main feedwater)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.D1.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-74	3.4.1-014	A

Table 3.4.2-5 Steam and Power Conversion System - Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (motor-driven auxiliary feedwater)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.D1.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-74	3.4.1-014	A
Pump casing (turbine-driven auxiliary feedwater)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.D1.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-74	3.4.1-014	A
Sight glass	LB;PB	Glass	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-33	3.4.1-055	A
			(I) Lubricating oil	None	None	VIII.I.SP-10	3.4.1-055	A
			(I) Treated water	None	None	VIII.I.SP-35	3.4.1-055	A
Sight glass (body)	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-92	3.4.1-043	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-92	3.4.1-043	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.D1.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-74	3.4.1-014	A
Tank (instrument air accumulator)	PB	Steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
Tank (main feed pump lube oil reservoir)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-91	3.4.1-040	A

Table 3.4.2-5 Steam and Power Conversion System - Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (motor-driven pump lube oil reservoir)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-91	3.4.1-040	A
Tank (turbine-driven pump lube oil reservoir)	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-91	3.4.1-040	A
Valve body	LB;PB;SI	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-92	3.4.1-043	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-92	3.4.1-043	A
		Polymer	(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-483a	3.4.1-135	A
			(I) Lubricating oil	Hardening or loss of strength; loss of material; cracking or blistering; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	None	None	G, 1
		Stainless steel	(I) Air – dry	Loss of material	Compressed Air Monitoring (B2.1.14)	VII.D.A-764	3.3.1-235	A
			(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.D1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-127a	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-95	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-95	3.4.1-044	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-98	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-155	3.4.1-084	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-87	3.4.1-085	A

Table 3.4.2-5 Steam and Power Conversion System - Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB;SI	Stainless steel	(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.D1.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.D1.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.D1.SP-91	3.4.1-040	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.D1.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.D1.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.D1.SP-74	3.4.1-014	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.SP-161	3.4.1-050	A

Table 3.4.2-5 Plant-Specific Notes:

1. Lubricating oil is not a GALL environment for polymeric material. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will manage aging effects for polymeric components exposed to lubricating oil.

Table 3.4.2-6 Steam and Power Conversion System - Condensate - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.SP-141	3.4.1-050	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
Expansion joint	LB	Elastomer	(E) Air – indoor uncontrolled	Hardening or loss of strength	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-428	3.4.1-077	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-471	3.4.1-122	A
			(I) Treated water	Hardening or loss of strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-75	3.3.1-085	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.AP-76	3.3.1-096	A
Flexible hose	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Heat exchanger (air ejector)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	A
Heat exchanger (condensate drain cooler - channel)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	A

Table 3.4.2-6 Steam and Power Conversion System - Condensate - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (condensate drain cooler - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
Heat exchanger (feedwater heater - channel)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	A
Heat exchanger (feedwater heater - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
Heat exchanger (gland steam condenser - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
Heat exchanger (gland steam condenser - waterbox)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	A
Heat exchanger (main condenser - hotwell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	A
Heat exchanger (main condenser - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A

Table 3.4.2-6 Steam and Power Conversion System - Condensate - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Manway	PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	V.A.E-29	3.2.1-044	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.E.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-127a	3.4.1-003	A
			(I) Treated water	Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(E) Underground	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.S-425b	3.4.1-074	A
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.S-443b	3.4.1-095	A

Table 3.4.2-6 Steam and Power Conversion System - Condensate - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Treated water	Cumulative fatigue damage	TLAA	VIII.D1.S-11	3.4.1-001	A
				Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.E.S-16	3.4.1-005	A
						VIII.D1.S-408	3.4.1-060	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.SP-161	3.4.1-050	A
Piping, piping components (exiting concrete into soil)	LB	Stainless steel	(E) Concrete	Cracking	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.S-420	3.4.1-072	A, 1
				Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.SP-145	3.4.1-047	A, 1
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Pump casing (condensate)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
					Selective Leaching (B2.1.21)	VIII.E.SP-27	3.4.1-033	A
Sight glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-33	3.4.1-055	A
			(I) Treated water	None	None	VIII.I.SP-35	3.4.1-055	A

Table 3.4.2-6 Steam and Power Conversion System - Condensate - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Sight glass (body)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.F.SP-101	3.4.1-016	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
Strainer body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
Tank (emergency condensate storage (110k gal))	PB	Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	Outdoor and Large Atmospheric Metallic Storage Tanks (B2.1.17)	VIII.E.SP-115	3.4.1-030	B
			(I) Treated water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VIII.E.S-401	3.4.1-066	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VIII.E.S-414	3.4.1-067	B
Valve body	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.F.SP-101	3.4.1-016	A
		Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-454	3.4.1-106	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.F.SP-101	3.4.1-016	A
					Selective Leaching (B2.1.21)	VIII.E.SP-55	3.4.1-033	A

Table 3.4.2-6 Steam and Power Conversion System - Condensate - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
					Selective Leaching (B2.1.21)	VIII.E.SP-27	3.4.1-033	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.E.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A

Table 3.4.2-6 Plant-Specific Notes:

1. Embedded piping provides an anchor for attached safety-related piping. The nonsafety-related piping exits into soil, but the buried portion is not within scope.

Table 3.4.2-7 Steam and Power Conversion System - Condensate Polishing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
Cation column	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Demineralizer shell	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-75	3.4.1-012	A
					Water Chemistry (B2.1.2)	VIII.E.SP-75	3.4.1-012	A
Drip pan	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-127a	3.4.1-003	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A
Filter housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Flow element	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Heat exchanger (sample cooler - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VIII.E.S-23	3.4.1-025	A

Table 3.4.2-7 Steam and Power Conversion System - Condensate Polishing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
Piping, piping components	LB	Polymer	(E) Air – indoor uncontrolled	Hardening or loss of strength; loss of material; cracking or blistering	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-483a	3.4.1-135	A
			(I) Treated water	Hardening or loss of strength; loss of material; cracking or blistering	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.S-483b	3.4.1-135	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VIII.E.S-23	3.4.1-025	C
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.E.S-16	3.4.1-005	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Pump casing (backwash recovery)	LB	Ductile iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
					Selective Leaching (B2.1.21)	VIII.E.SP-27	3.4.1-033	A

Table 3.4.2-7 Steam and Power Conversion System - Condensate Polishing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (backwash)	LB	Ductile iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
					Selective Leaching (B2.1.21)	VIII.E.SP-27	3.4.1-033	A
Pump casing (hold pump)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
Pump casing (precoat)	LB	Ductile iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
					Selective Leaching (B2.1.21)	VIII.E.SP-27	3.4.1-033	A
Pump casing (spent resin transfer)	LB	Ductile iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
					Selective Leaching (B2.1.21)	VIII.E.SP-27	3.4.1-033	A
Sight glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-33	3.4.1-055	A
			(I) Treated water	None	None	VIII.I.SP-35	3.4.1-055	A
Sight glass (body)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A

Table 3.4.2-7 Steam and Power Conversion System - Condensate Polishing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Strainer body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
Tank (A recovery compartment)	LB	Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VIII.E.S-401	3.4.1-066	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VIII.E.S-414	3.4.1-067	B
Tank (B recovery compartment)	LB	Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VIII.E.S-401	3.4.1-066	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VIII.E.S-414	3.4.1-067	B
Tank (precoat)	LB	Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VIII.E.S-401	3.4.1-066	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VIII.E.S-414	3.4.1-067	B

Table 3.4.2-7 Steam and Power Conversion System - Condensate Polishing - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (secondary phase separator)	LB	Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VIII.E.S-401	3.4.1-066	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VIII.E.S-414	3.4.1-067	B
Valve body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.E.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-202	3.3.1-045	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A

Table 3.4.2-7 Plant-Specific Notes: None

Table 3.4.2-8 Steam and Power Conversion System - Steam Drains - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
Expansion joint	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-87	3.4.1-085	A
Filter housing	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Flow element	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
Heat exchanger (heater drain pump lube oil cooler - channel)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.S-438	3.4.1-091	A
Heat exchanger (heater drain pump lube oil cooler - shell)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	C
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-92	3.4.1-043	C
					One-Time Inspection (B2.1.20)	VIII.A.SP-92	3.4.1-043	C

Table 3.4.2-8 Steam and Power Conversion System - Steam Drains - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Level indicator	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-87	3.4.1-085	A
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.A.SP-98	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.A.SP-155	3.4.1-084	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-87	3.4.1-085	A
Piping, piping components	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-95	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-95	3.4.1-044	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-88	3.4.1-011	A
				Cumulative fatigue damage	TLAA	VII.E1.A-57	3.3.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-87	3.4.1-085	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.D1.S-408	3.4.1-060	A

Table 3.4.2-8 Steam and Power Conversion System - Steam Drains - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	V.A.E-29	3.2.1-044	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
			(I) Steam	Cumulative fatigue damage	TLAA	VIII.B1.S-08	3.4.1-001	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.A.SP-71	3.4.1-014	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.A.S-15	3.4.1-005	A
						VIII.B1.S-408	3.4.1-060	A
			(I) Treated water	Cumulative fatigue damage	TLAA	VIII.B1.S-08	3.4.1-001	A
				Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.E.S-16	3.4.1-005	A
						VIII.D1.S-408	3.4.1-060	A
Pump casing (high-pressure heater drain - head assembly)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.A.S-436	3.4.1-089	A
Pump casing (high-pressure heater drain)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A

Table 3.4.2-8 Steam and Power Conversion System - Steam Drains - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (low-pressure heater drain)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
Pump casing (shaft-driven lube oil pump)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Sight glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-33	3.4.1-055	A
			(I) Lubricating oil	None	None	VIII.I.SP-10	3.4.1-055	A
			(I) Treated water	None	None	VIII.I.SP-35	3.4.1-055	A
Sight glass (body)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-92	3.4.1-043	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-92	3.4.1-043	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-87	3.4.1-085	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A

Table 3.4.2-8 Steam and Power Conversion System - Steam Drains - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Strainer body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A
Tank (2nd point heater drain receiver)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-75	3.4.1-012	A
					Water Chemistry (B2.1.2)	VIII.E.SP-75	3.4.1-012	A
Tank (lube oil reservoir)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Tank (MSR drain receiver)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-75	3.4.1-012	A
					Water Chemistry (B2.1.2)	VIII.E.SP-75	3.4.1-012	A
Tank (reheater drain receiver)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-75	3.4.1-012	A
					Water Chemistry (B2.1.2)	VIII.E.SP-75	3.4.1-012	A
Trap body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.A.SP-71	3.4.1-014	A

Table 3.4.2-8 Steam and Power Conversion System - Steam Drains - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-92	3.4.1-043	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-92	3.4.1-043	A
		Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-454	3.4.1-106	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.A.SP-101	3.4.1-016	A
					Selective Leaching (B2.1.21)	VIII.E.SP-55	3.4.1-033	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-127a	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-95	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-95	3.4.1-044	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.A.SP-98	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.A.SP-155	3.4.1-084	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-87	3.4.1-085	A

Table 3.4.2-8 Steam and Power Conversion System - Steam Drains - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.A.SP-71	3.4.1-014	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.A.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-73	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.E.SP-73	3.4.1-014	A

Table 3.4.2-8 Plant-Specific Notes: None

Table 3.4.2-9 Steam and Power Conversion System - Blowdown - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.SP-141	3.4.1-050	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
Flow element	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
Heat exchanger (blowdown flash tank drains - channel)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.F.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	A
Heat exchanger (blowdown flash tank drains - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.F.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-77	3.4.1-015	A
					Water Chemistry (B2.1.2)	VIII.E.SP-77	3.4.1-015	A
Heat exchanger (blowdown vent condenser - channel)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	C
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	C
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-98	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-155	3.4.1-084	C
					Water Chemistry (B2.1.2)	VIII.B1.SP-155	3.4.1-084	C

Table 3.4.2-9 Steam and Power Conversion System - Blowdown - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (blowdown vent condenser - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Closed–cycle cooling water	Loss of material	Closed Treated Water Systems (B2.1.12)	VIII.F.S-23	3.4.1-025	A
Insulation (containment penetration)	TI	Non-metallic thermal insulation	(E) Air – indoor uncontrolled	Reduced thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-403	3.4.1-064	A
Orifice	LB;PB;RF	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.F.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
Piping, piping components	LB;PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.F.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.D1.S-408	3.4.1-060	A

Table 3.4.2-9 Steam and Power Conversion System - Blowdown - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	V.A.E-29	3.2.1-044	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Steam	Cumulative fatigue damage	TLAA	VIII.B1.S-08	3.4.1-001	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.B1.S-15	3.4.1-005	A
			(I) Treated water	Cumulative fatigue damage	TLAA	VIII.B1.S-08	3.4.1-001	A
				Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.F.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.F.SP-74	3.4.1-014	A
				Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.F.S-16	3.4.1-005	A
						VIII.D1.S-408	3.4.1-060	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.SP-161	3.4.1-050	A
Pump casing (sampling transfer)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
Radiation monitor housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
Sight glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-33	3.4.1-055	A
			(I) Treated water	None	None	VIII.I.SP-35	3.4.1-055	A

Table 3.4.2-9 Steam and Power Conversion System - Blowdown - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Sight glass (body)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
Tank (blowdown flash)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.F.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.F.SP-74	3.4.1-014	A
Tank (condensate pot)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.F.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.F.SP-74	3.4.1-014	A
Tank (proportional sampler)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-162	3.4.1-083	A
					Water Chemistry (B2.1.2)	VIII.E.SP-162	3.4.1-083	A

Table 3.4.2-9 Steam and Power Conversion System - Blowdown - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (steam generator blowdown)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.F.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.F.SP-74	3.4.1-014	A
Valve body	LB;PB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-454	3.4.1-106	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-101	3.4.1-016	A
					Water Chemistry (B2.1.2)	VIII.F.SP-101	3.4.1-016	A
					Selective Leaching (B2.1.21)	VIII.F.SP-55	3.4.1-033	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-127a	3.4.1-003	A
			(I) Steam	Cracking	One-Time Inspection (B2.1.20)	VIII.B1.SP-98	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-98	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-155	3.4.1-084	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-155	3.4.1-084	A
			(I) Treated water	Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A
			(I) Treated water >60°C (>140°F)	Cracking	One-Time Inspection (B2.1.20)	VIII.F.SP-88	3.4.1-011	A
					Water Chemistry (B2.1.2)	VIII.F.SP-88	3.4.1-011	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-87	3.4.1-085	A
					Water Chemistry (B2.1.2)	VIII.F.SP-87	3.4.1-085	A

Table 3.4.2-9 Steam and Power Conversion System - Blowdown - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Air – indoor uncontrolled	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	V.A.E-29	3.2.1-044	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	VIII.H.S-30	3.4.1-004	A
			(I) Steam	Loss of material	One-Time Inspection (B2.1.20)	VIII.B1.SP-71	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.B1.SP-71	3.4.1-014	A
			(I) Treated water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.F.S-432	3.4.1-081	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.F.SP-74	3.4.1-014	A
					Water Chemistry (B2.1.2)	VIII.F.SP-74	3.4.1-014	A
			(E) Underground	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VIII.H.SP-161	3.4.1-050	A

Table 3.4.2-9 Plant-Specific Notes: None

Table 3.4.2-10 Steam and Power Conversion System - Lubricating Oil - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
Filter housing	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Flow element	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-272	3.3.1-095	A
Heat exchanger (turbine lube oil cooler - channel)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	Selective Leaching (B2.1.21)	VIII.A.SP-28	3.4.1-033	C
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.S-438	3.4.1-091	A
Heat exchanger (turbine lube oil cooler - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-76	3.4.1-041	A
					One-Time Inspection (B2.1.20)	VIII.G.SP-76	3.4.1-041	A
Heater housing	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-95	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-95	3.4.1-044	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-278	3.3.1-095	A

Table 3.4.2-10 Steam and Power Conversion System - Lubricating Oil - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-95	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-95	3.4.1-044	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
Pump casing (bearing oil lift)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Pump casing (conditioner skid)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Pump casing (conditioner supply)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Pump casing (fill)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Pump casing (main lube oil)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A

Table 3.4.2-10 Steam and Power Conversion System - Lubricating Oil - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (seal oil backup)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Sight glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-33	3.4.1-055	A
			(I) Lubricating oil	None	None	VIII.I.SP-10	3.4.1-055	A
			(I) Waste water	None	None	VII.J.AP-277	3.3.1-119	A
Sight glass (body)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-272	3.3.1-095	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Strainer body	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Tank (clean oil tank)	LB	Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VIII.E.S-401	3.4.1-066	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VIII.E.S-414	3.4.1-067	B

Table 3.4.2-10 Steam and Power Conversion System - Lubricating Oil - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (turbine lube oil reservoir)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Tank (used oil tank)	LB	Steel with internal coating	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of coating or lining integrity	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VIII.E.S-401	3.4.1-066	B
				Loss of material	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VIII.E.S-414	3.4.1-067	B
Valve body	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-92	3.4.1-043	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-92	3.4.1-043	A
			(I) Waste water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-272	3.3.1-095	A
		Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-454	3.4.1-106	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-92	3.4.1-043	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-92	3.4.1-043	A
			(I) Waste water	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-473c	3.3.1-160	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-547	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-272	3.3.1-095	A

Table 3.4.2-10 Steam and Power Conversion System - Lubricating Oil - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-724	3.3.1-072	A
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-95	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-95	3.4.1-044	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
			(I) Waste water	Long-term loss of material	One-Time Inspection (B2.1.20)	VII.E5.A-785	3.3.1-193	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-281	3.3.1-091	A

Table 3.4.2-10 Plant-Specific Notes: None

Table 3.4.2-11 Steam and Power Conversion System - Main Generator Seal Oil - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
Filter housing	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Flexible hose	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-95	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-95	3.4.1-044	A
Heat exchanger (air side oil cooler - channel)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.S-438	3.4.1-091	A
Heat exchanger (air side oil cooler - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-76	3.4.1-041	A
					One-Time Inspection (B2.1.20)	VIII.G.SP-76	3.4.1-041	A
Heat exchanger (exciter air cooler - channel)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.S-438	3.4.1-091	A
Heat exchanger (exciter air cooler - tube)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	C
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.S-438	3.4.1-091	A

Table 3.4.2-11 Steam and Power Conversion System - Main Generator Seal Oil - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (generator leads cooler - channel)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.S-438	3.4.1-091	A
Heat exchanger (generator leads cooler - tube)	LB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	C
			(I) Raw water	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.S-438	3.4.1-091	A
Heat exchanger (hydrogen side oil cooler - channel)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.S-438	3.4.1-091	A
Heat exchanger (hydrogen side oil cooler - shell)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-76	3.4.1-041	A
					One-Time Inspection (B2.1.20)	VIII.G.SP-76	3.4.1-041	A
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-95	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-95	3.4.1-044	A

Table 3.4.2-11 Steam and Power Conversion System - Main Generator Seal Oil - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Condensation	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-95	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-95	3.4.1-044	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Gas	None	None	VIII.I.SP-4	3.4.1-059	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Pump casing (air side seal oil)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Pump casing (hydrogen side seal oil)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Sight glass	LB	Glass	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-33	3.4.1-055	A
			(I) Condensation	None	None	VIII.I.SP-68	3.4.1-055	A
			(I) Lubricating oil	None	None	VIII.I.SP-10	3.4.1-055	A

Table 3.4.2-11 Steam and Power Conversion System - Main Generator Seal Oil - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Sight glass (body)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Condensation	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Tank (dryer vent condensate drain)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Condensation	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
Tank (generator loop seal)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Tank (hydrogen side drain regulator)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Tank (hydrogen side receiver)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
Tank (prefilter sump)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Condensation	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A

Table 3.4.2-11 Steam and Power Conversion System - Main Generator Seal Oil - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (water detector)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Gas	None	None	VIII.I.SP-4	3.4.1-059	A
Valve body	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Condensation	Cracking	One-Time Inspection (B2.1.20)	VIII.A.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.A.SP-127a	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-95	3.4.1-044	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-95	3.4.1-044	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Gas	None	None	VIII.I.SP-4	3.4.1-059	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.A.SP-91	3.4.1-040	A
					One-Time Inspection (B2.1.20)	VIII.A.SP-91	3.4.1-040	A

Table 3.4.2-11 Plant-Specific Notes: None

Table 3.4.2-12 Steam and Power Conversion System - Electro-Hydraulic Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	Bolting Integrity (B2.1.9)	VIII.H.S-02	3.4.1-009	A
				Loss of preload	Bolting Integrity (B2.1.9)	VIII.H.SP-142	3.4.1-006	A
Filter housing	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-127a	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.E.SP-95	3.4.1-044	A, 1
					One-Time Inspection (B2.1.20)	VIII.E.SP-95	3.4.1-044	A, 1
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.E.SP-91	3.4.1-040	A, 1
					One-Time Inspection (B2.1.20)	VIII.E.SP-91	3.4.1-040	A, 1
Filter housing (duplex filter - head)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.E.SP-91	3.4.1-040	A, 1
					One-Time Inspection (B2.1.20)	VIII.E.SP-91	3.4.1-040	A, 1
Filter housing (duplex filter)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.E.SP-91	3.4.1-040	A, 1
					One-Time Inspection (B2.1.20)	VIII.E.SP-91	3.4.1-040	A, 1
Flexible hose	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-127a	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.E.SP-95	3.4.1-044	A, 1
					One-Time Inspection (B2.1.20)	VIII.E.SP-95	3.4.1-044	A, 1
Flow element	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-127a	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.E.SP-95	3.4.1-044	A, 1
					One-Time Inspection (B2.1.20)	VIII.E.SP-95	3.4.1-044	A, 1

Table 3.4.2-12 Steam and Power Conversion System - Electro-Hydraulic Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (EHC cooler - channel)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Raw water	Long-term loss of material	One-Time Inspection (B2.1.20)	VIII.E.S-432	3.4.1-081	A
				Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VIII.E.S-438	3.4.1-091	A
Heat exchanger (EHC cooler - shell)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-118a	3.4.1-002	C
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-127a	3.4.1-003	C
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.G.SP-79	3.4.1-044	A, 1
					One-Time Inspection (B2.1.20)	VIII.G.SP-79	3.4.1-044	A, 1
Orifice	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-127a	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.E.SP-95	3.4.1-044	A, 1
					One-Time Inspection (B2.1.20)	VIII.E.SP-95	3.4.1-044	A, 1
Piping, piping components	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-127a	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.E.SP-95	3.4.1-044	A, 1
					One-Time Inspection (B2.1.20)	VIII.E.SP-95	3.4.1-044	A, 1
Pump casing (EHC pump)	LB	Gray cast iron	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.E.SP-91	3.4.1-040	A, 1
					One-Time Inspection (B2.1.20)	VIII.E.SP-91	3.4.1-040	A, 1
Tank (EHC reservoir)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-127a	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.E.SP-95	3.4.1-044	A, 1
					One-Time Inspection (B2.1.20)	VIII.E.SP-95	3.4.1-044	A, 1
Tank (high-pressure accumulator)	LB	Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Gas	None	None	VIII.I.SP-4	3.4.1-059	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.E.SP-91	3.4.1-040	A, 1
					One-Time Inspection (B2.1.20)	VIII.E.SP-91	3.4.1-040	A, 1

Table 3.4.2-12 Steam and Power Conversion System - Electro-Hydraulic Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Tank (low-pressure accumulator)	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-127a	3.4.1-003	A
			(I) Gas	None	None	VIII.I.SP-15	3.4.1-058	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.E.SP-95	3.4.1-044	A, 1
					One-Time Inspection (B2.1.20)	VIII.E.SP-95	3.4.1-044	A, 1
Valve body	LB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	One-Time Inspection (B2.1.20)	VIII.E.SP-118a	3.4.1-002	A
				Loss of material	One-Time Inspection (B2.1.20)	VIII.E.SP-127a	3.4.1-003	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.E.SP-95	3.4.1-044	A, 1
					One-Time Inspection (B2.1.20)	VIII.E.SP-95	3.4.1-044	A, 1
		Steel	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-29	3.4.1-034	A
			(I) Lubricating oil	Loss of material	Lubricating Oil Analysis (B2.1.26)	VIII.E.SP-91	3.4.1-040	A, 1
					One-Time Inspection (B2.1.20)	VIII.E.SP-91	3.4.1-040	A, 1

Table 3.4.2-12 Plant-Specific Notes:

1. Electro-hydraulic fluid is Fyrquel® 220, a phosphate ester that is similar to lubricating oil for aging management evaluations. Fyrquel® is compatible with materials used in the system.

Tables 3.4.2-1 through 3.4.2-13 Industry Standard Notes:

A. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

B. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.

C. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

D. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to the NUREG-2191 AMP.

E. Consistent with NUREG-2191 item for 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.

G. Environment not in NUREG-2191 for this component and material.

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.

J. Neither the component nor the material and environment combination is evaluated in NUREG-2191.

3.5 AGING MANAGEMENT OF CONTAINMENT, STRUCTURES AND COMPONENT SUPPORTS

3.5.1 INTRODUCTION

This section provides the results of the aging management review for those components identified in Section 2.4.1, Containments, Structures, and Component Supports, as being subject to aging management review. The systems, or portions of systems, which are addressed in this section are described in the indicated sections.

- Containment (Section 2.4.1.1)
- Administration Building (Section 2.4.1.2)
- Auxiliary Building (Section 2.4.1.3)
- Auxiliary Feedwater Pump House (Section 2.4.1.4)
- Auxiliary Feedwater Tunnel (Section 2.4.1.5)
- Boron Recovery Building (Section 2.4.1.6)
- Casing Cooling Pump House (Section 2.4.1.7)
- Circulating Water Intake Tunnel Header (Section 2.4.1.8)
- Containment Mat Subsurface Pump Access Shaft (Section 2.4.1.9)
- Decontamination Building (Section 2.4.1.10)
- Dikes, Firewalls, and Equipment Foundations (Section 2.4.1.11)
- Discharge Tunnel & Seal Pit (Section 2.4.1.12)
- Domestic Water Treatment Building (Section 2.4.1.13)
- Duct Banks (Section 2.4.1.14)
- Flood Protection Dike (Section 2.4.1.15)
- Fuel Building (Section 2.4.1.16)
- Fuel Oil Pump House (Section 2.4.1.17)
- Intake Structure (Section 2.4.1.18)
- Main Steam Valve House (Section 2.4.1.19)
- Maintenance Building (Section 2.4.1.20)
- Manholes (Section 2.4.1.21)
- New Fuel Receiving Building (Section 2.4.1.22)
- Quench Spray Pump House (Section 2.4.1.23)
- Safeguards Building (Section 2.4.1.24)

- SBO Building (Section 2.4.1.25)
- SBO Structures for Offsite Power (Section 2.4.1.26)
- Security Diesel Building (Section 2.4.1.27)
- Security Lighting Poles (Section 2.4.1.28)
- Service Building (Section 2.4.1.29)
- Service Water Pump House (Section 2.4.1.30)
- Service Water Reservoir (Section 2.4.1.31)
- Service Water Valve House (Section 2.4.1.32)
- Tank Foundations and Missile Barriers (Section 2.4.1.33)
- Turbine Building (Section 2.4.1.34)
- Vaults, Enclosures, and Pits (Section 2.4.1.35)
- Waste Disposal Building (Section 2.4.1.36)
- Waste Solidification Building (Section 2.4.1.37)
- Component Supports (Section 2.4.1.38)
- Miscellaneous Structural Commodities (Section 2.4.1.39)
- NSSS Supports (Section 2.4.1.40)

3.5.2 RESULTS

The following table summarize the results of the aging management review for Containment, Structures and Component Supports.

- Table 3.5.2-1, Containment Structure - Aging Management Evaluation
- Table 3.5.2-2, Structures and Component Supports - Administration Building - Aging Management Evaluation
- Table 3.5.2-3, Structures and Component Supports - Auxiliary Building - Aging Management Evaluation
- Table 3.5.2-4, Structures and Component Supports - Auxiliary Feedwater Pump House - Aging Management Evaluation
- Table 3.5.2-5, Structures and Component Supports - Auxiliary Feedwater Tunnel - Aging Management Evaluation
- Table 3.5.2-6, Structures and Component Supports - Boron Recovery Building - Aging Management Evaluation
- Table 3.5.2-7, Structures and Component Supports - Casing Cooling Pump House - Aging Management Evaluation
- Table 3.5.2-8, Structures and Component Supports - Circulating Water Intake Tunnel Header - Aging Management Evaluation
- Table 3.5.2-9, Structures and Component Supports - Containment Mat Subsurface Pump Access Shaft - Aging Management Evaluation
- Table 3.5.2-10, Structures and Component Supports - Decontamination Building - Aging Management Evaluation
- Table 3.5.2-11, Structures and Component Supports - Dikes, Firewalls, and Equipment Foundations - Aging Management Evaluation
- Table 3.5.2-12, Structures and Component Supports - Discharge Tunnel & Seal Pit - Aging Management Evaluation
- Table 3.5.2-13, Structures and Component Supports - Domestic Water Treatment Building - Aging Management Evaluation
- Table 3.5.2-14, Structures and Component Supports - Duct Banks - Aging Management Evaluation
- Table 3.5.2-15, Structures and Component Supports - Flood Protection Dike - Aging Management Evaluation
- Table 3.5.2-16, Structures and Component Supports - Fuel Building - Aging Management Evaluation

- Table 3.5.2-34, Structures and Component Supports - Turbine Building - Aging Management Evaluation
- Table 3.5.2-35, Structures and Component Supports - Vaults, Enclosures, and Pits - Aging Management Evaluation
- Table 3.5.2-36, Structures and Component Supports - Waste Disposal Building - Aging Management Evaluation
- Table 3.5.2-37, Structures and Component Supports - Waste Solidification Building - Aging Management Evaluation
- Table 3.5.2-38, Structures and Component Supports - Component Supports - Aging Management Evaluation
- Table 3.5.2-39, Structures and Component Supports - Miscellaneous Structural Commodities - Aging Management Evaluation
- Table 3.5.2-40, Structures and Component Supports - NSSS Supports - Aging Management Evaluation

3.5.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.5.2.1.1 Containment

Materials

The materials of construction for the containment structural members are:

- Coatings
- Concrete
- Concrete block
- Dissimilar metal welds
- Elastomer, rubber and other similar materials
- Porous concrete
- Reinforced concrete
- Stainless steel
- Steel

Environment

The containment structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Groundwater
- Soil
- Treated borated water
- Water – flowing
- Water – standing

Aging Effects Requiring Management

The following aging effects, associated with the containment structural members, require management:

- Cracking
- Cracking and distortion
- Cumulative fatigue damage
- Increase in porosity and permeability
- Loss of bond
- Loss of coating or lining integrity
- Loss of leak tightness
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the containment structural members:

- 10 CFR Part 50, Appendix J (B2.1.32)
- ASME Section XI, Subsection IWE (B2.1.29)
- ASME Section XI, Subsection IWL (B2.1.30)
- Boric Acid Corrosion (B2.1.4)
- Fire Protection (B2.1.15)
- Masonry Walls (B2.1.33)
- Protective Coating Monitoring and Maintenance (B2.1.36)
- Structures Monitoring (B2.1.34)
- Water Chemistry (B2.1.2)

3.5.2.1.2 Administration Building

Materials

The materials of construction for the administration building structural members are:

- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Masonry walls
- Steel

Environment

The administration building structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the administration building structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the administration building structural members:

- Fire Protection (B2.1.15)
- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.3 Auxiliary Building

Materials

The materials of construction for the auxiliary building structural members are:

- Aluminum
- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Masonry walls
- Reinforced concrete
- Steel

Environment

The auxiliary building structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the auxiliary building structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the auxiliary building structural members:

- Boric Acid Corrosion (B2.1.4)
- Fire Protection (B2.1.15)
- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.4 Auxiliary Feedwater Pump House

Materials

The materials of construction for the auxiliary feedwater pump house structural members are:

- Concrete
- Reinforced concrete
- Steel

Environment

The auxiliary feedwater pump house structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the auxiliary feedwater pump house structural members, require management:

- Cracking
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the auxiliary feedwater pump house structural members:

- Fire Protection (B2.1.15)
- Structures Monitoring (B2.1.34)

3.5.2.1.5 Auxiliary Feedwater Tunnel

Materials

The materials of construction for the auxiliary feedwater tunnel structural members are:

- Concrete
- Stainless steel
- Steel

Environment

The auxiliary feedwater tunnel structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the auxiliary feedwater tunnel structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the auxiliary feedwater tunnel structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.6 Boron Recovery Building

Materials

The materials of construction for the boron recovery building structural members are:

- Aluminum
- Concrete
- Elastomer, rubber and other similar materials
- Steel

Environment

The boron recovery building structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the boron recovery building structural members, require management:

- Cracking
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the boron recovery building structural members:

- Boric Acid Corrosion (B2.1.4)
- Structures Monitoring (B2.1.34)

3.5.2.1.7 Casing Cooling Pump House

Materials

The materials of construction for the casing cooling pump house structural members are:

- Aluminum
- Concrete
- Elastomer, rubber and other similar materials
- Steel

Environment

The casing cooling pump house structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the casing cooling pump house structural members, require management:

- Cracking
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the casing cooling pump house structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.8 Circulating Water Intake Tunnel Header

Materials

The materials of construction for the circulating water intake tunnel header structural members are:

- Concrete
- Steel

Environment

The circulating water intake tunnel header structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the circulating water intake tunnel header structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the circulating water intake tunnel header structural members:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)
- Structures Monitoring (B2.1.34)

3.5.2.1.9 Containment Mat Subsurface Pump Access Shaft

Materials

The materials of construction for the containment mat subsurface pump access shaft structural members are:

- Concrete

Environment

The containment mat subsurface pump access shaft structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the containment mat subsurface pump access shaft structural members, require management:

- Cracking
- Increase in porosity and permeability
- Loss of bond
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the containment mat subsurface pump access shaft structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.10 Decontamination Building

Materials

The materials of construction for the decontamination building structural members are:

- Aluminum
- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Steel

Environment

The decontamination building structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the decontamination building structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the decontamination building structural members:

- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.11 Dikes, Firewalls, and Equipment Foundations

Materials

The materials of construction for the dikes, firewalls, and equipment foundations structural members are:

- Concrete
- Steel

Environment

The dikes, firewalls, and equipment foundations structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the dikes, firewalls, and equipment foundations structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the dikes, firewalls, and equipment foundations structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.12 Discharge Tunnel & Seal Pit

Materials

The materials of construction for the discharge tunnel & seal pit structural members are:

- Concrete

Environment

The discharge tunnel & seal pit structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the discharge tunnel & seal pit structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the discharge tunnel & seal pit structural members:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)
- Structures Monitoring (B2.1.34)

3.5.2.1.13 Domestic Water Treatment Building

Materials

The materials of construction for the domestic water treatment building structural members are:

- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Steel

Environment

The domestic water treatment building structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the domestic water treatment building structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the domestic water treatment building structural members:

- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.14 Duct Banks

Materials

The materials of construction for the duct banks structural members are:

- Concrete

Environment

The duct banks structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the duct banks structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the duct banks structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.15 Flood Protection Dike

Materials

The materials of construction for the flood protection dike structural members are:

- Any material with an internal coating/lining
- Concrete
- Earthfill (rip-rap, stone, soil)
- Gray cast iron
- Stainless steel
- Steel

Environment

The flood protection dike structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Raw water
- Soil
- Water – flowing
- Water – standing

Aging Effects Requiring Management

The following aging effects, associated with the flood protection dike structural members, require management:

- Cracking
- Increase in porosity and permeability
- Loss of bond
- Loss of coating or lining integrity
- Loss of form
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of material or cracking
- Loss of preload
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the flood protection dike structural members:

- Buried and Underground Piping and Tanks (B2.1.27)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- Selective Leaching (B2.1.21)
- Structures Monitoring (B2.1.34)

3.5.2.1.16 Fuel Building

Materials

The materials of construction for the fuel building structural members are:

- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Stainless steel
- Steel

Environment

The fuel building structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Groundwater
- Soil
- Treated borated water
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the fuel building structural members, require management:

- Cracking
- Cumulative fatigue damage
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the fuel building structural members:

- Boric Acid Corrosion (B2.1.4)
- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)
- Water Chemistry (B2.1.2)

3.5.2.1.17 Fuel Oil Pump House

Materials

The materials of construction for the fuel oil pump house structural members are:

- Concrete
- Reinforced concrete
- Steel

Environment

The fuel oil pump house structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the fuel oil pump house structural members, require management:

- Cracking
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the fuel oil pump house structural members:

- Fire Protection (B2.1.15)
- Structures Monitoring (B2.1.34)

3.5.2.1.18 Intake Structure

Materials

The materials of construction for the intake structure structural members are:

- Aluminum
- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Steel

Environment

The intake structure structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing
- Water – standing

Aging Effects Requiring Management

The following aging effects, associated with the intake structure structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the intake structure structural members:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)
- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.19 Main Steam Valve House

Materials

The materials of construction for the main steam valve house structural members are:

- Concrete
- Concrete block
- Reinforced concrete
- Steel

Environment

The main steam valve house structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the main steam valve house structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the main steam valve house structural members:

- Fire Protection (B2.1.15)
- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.20 Maintenance Building

Materials

The materials of construction for the maintenance building structural members are:

- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Steel

Environment

The maintenance building structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the maintenance building structural members, require management:

- Cracking
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the maintenance building structural members:

- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.21 Manholes

Materials

The materials of construction for the manholes structural members are:

- Concrete
- Steel

Environment

The manholes structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the manholes structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the manholes structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.22 New Fuel Receiving Building

Materials

The materials of construction for the new fuel receiving building structural members are:

- Aluminum
- Concrete
- Elastomer, rubber and other similar materials
- Steel

Environment

The new fuel receiving building structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the new fuel receiving building structural members, require management:

- Cracking
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the new fuel receiving building structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.23 Quench Spray Pump House

Materials

The materials of construction for the quench spray pump house structural members are:

- Aluminum
- Concrete
- Elastomer, rubber and other similar materials
- Reinforced concrete
- Steel

Environment

The quench spray pump house structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the quench spray pump house structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the quench spray pump house structural members:

- Fire Protection (B2.1.15)
- Structures Monitoring (B2.1.34)

3.5.2.1.24 Safeguards Building

Materials

The materials of construction for the safeguards building structural members are:

- Concrete
- Steel

Environment

The safeguards building structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the safeguards building structural members, require management:

- Cracking
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the safeguards building structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.25 SBO Building

Materials

The materials of construction for the SBO building structural members are:

- Aluminum
- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Steel

Environment

The SBO building structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the SBO building structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the SBO building structural members:

- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.26 SBO Structures for Offsite Power

Materials

The materials of construction for the SBO structures for offsite power structural members are:

- Concrete
- Elastomer, rubber and other similar materials
- Polymeric
- Steel

Environment

The SBO structures for offsite power structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the SBO structures for offsite power structural members, require management:

- Cracking
- Cracking and distortion
- Cracking or blistering
- Hardening or loss of strength
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the SBO structures for offsite power structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.27 Security Diesel Building

Materials

The materials of construction for the security diesel building structural members are:

- Concrete
- Steel

Environment

The security diesel building structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the security diesel building structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the security diesel building structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.28 Security Lighting Poles

Materials

The materials of construction for the security lighting poles structural members are:

- Concrete
- Steel

Environment

The security lighting poles structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the security lighting poles structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the security lighting poles structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.29 Service Building

Materials

The materials of construction for the service building structural members are:

- Aluminum
- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Masonry walls
- Reinforced concrete
- Steel

Environment

The service building structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the service building structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the service building structural members:

- Fire Protection (B2.1.15)
- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.30 Service Water Pump House

Materials

The materials of construction for the service water pump house structural members are:

- Concrete
- Steel

Environment

The service water pump house structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing
- Water – standing

Aging Effects Requiring Management

The following aging effects, associated with the service water pump house structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the service water pump house structural members:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)
- Structures Monitoring (B2.1.34)

3.5.2.1.31 Service Water Reservoir

Materials

The materials of construction for the service water reservoir structural members are:

- Concrete
- Earthfill (rip-rap, stone, soil)

Environment

The service water reservoir structural members are exposed to the following environments:

- Air – outdoor
- Water – flowing
- Water – standing

Aging Effects Requiring Management

The following aging effects, associated with the service water reservoir structural members, require management:

- Cracking
- Loss of form
- Loss of material

Aging Management Programs

The following aging management programs manage the aging effects for the service water reservoir structural members:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)
- Structures Monitoring (B2.1.34)

3.5.2.1.32 Service Water Valve House

Materials

The materials of construction for the service water valve house structural members are:

- Concrete
- Steel

Environment

The service water valve house structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the service water valve house structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the service water valve house structural members:

- Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)
- Structures Monitoring (B2.1.34)

3.5.2.1.33 Tank Foundations and Missile Barriers

Materials

The materials of construction for the tank foundations and missile barriers structural members are:

- Concrete
- Elastomer, rubber and other similar materials
- Grout
- Stainless steel
- Steel

Environment

The tank foundations and missile barriers structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the tank foundations and missile barriers structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength
- Reduction in concrete anchor capacity

Aging Management Programs

The following aging management programs manage the aging effects for the tank foundations and missile barriers structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.34 Turbine Building

Materials

The materials of construction for the turbine building structural members are:

- Aluminum
- Concrete
- Concrete block
- Elastomer, rubber and other similar materials
- Masonry walls
- Reinforced concrete
- Steel

Environment

The turbine building structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the turbine building structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the turbine building structural members:

- Fire Protection (B2.1.15)
- Masonry Walls (B2.1.33)
- Structures Monitoring (B2.1.34)

3.5.2.1.35 Vaults, Enclosures, and Pits

Materials

The materials of construction for the vaults, enclosures, and pits structural members are:

- Concrete
- Steel

Environment

The vaults, enclosures, and pits structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the vaults, enclosures, and pits structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the vaults, enclosures, and pits structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.36 Waste Disposal Building

Materials

The materials of construction for the waste disposal building structural members are:

- Aluminum
- Concrete
- Elastomer, rubber and other similar materials
- Steel

Environment

The waste disposal building structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the waste disposal building structural members, require management:

- Cracking
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the waste disposal building structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.37 Waste Solidification Building

Materials

The materials of construction for the waste solidification building structural members are:

- Aluminum
- Concrete
- Elastomer, rubber and other similar materials
- Steel

Environment

The waste solidification building structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the waste solidification building structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the waste solidification building structural members:

- Structures Monitoring (B2.1.34)

3.5.2.1.38 Component Supports

Materials

The materials of construction for the component supports subcomponents are:

- Aluminum
- Grout
- Lubrite®
- Non-metallic (e.g., rubber)
- Stainless steel
- Steel

Environment

The component supports subcomponents are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Raw water
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the component supports subcomponents, require management:

- Cracking
- Loss of material
- Loss of mechanical function
- Loss of preload
- Reduction in concrete anchor capacity
- Reduction or loss of isolation function

Aging Management Programs

The following aging management programs manage the aging effects for the component supports subcomponents:

- ASME Section XI, Subsection IWF (B2.1.31)
- Boric Acid Corrosion (B2.1.4)
- Structures Monitoring (B2.1.34)

3.5.2.1.39 Miscellaneous Structural Commodities

Materials

The materials of construction for the miscellaneous structural commodities subcomponents are:

- Aluminum
- Cementitious coatings (Pyrocrete, BIO™ K-10 Mortar, Cafecote, and other similar materials)
- Elastomer
- Elastomer, rubber and other similar materials
- Silicates (Marinite®, Kaowool™, Cerafiber®, Cera® blanket, or other similar materials)
- Stainless steel
- Steel
- Subliming compound fireproofing/fire barriers (Thermo-Lag®, Darmatt™, 3M™ Interam™, and other similar materials)

Environment

The miscellaneous structural commodities subcomponents are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Groundwater
- Soil

Aging Effects Requiring Management

The following aging effects, associated with the miscellaneous structural commodities subcomponents, require management:

- Cracking
- Hardening, loss of strength, shrinkage
- Loss of material
- Loss of preload
- Loss of sealing

Aging Management Programs

The following aging management programs manage the aging effects for the miscellaneous structural commodities subcomponents:

- Boric Acid Corrosion (B2.1.4)
- Fire Protection (B2.1.15)
- Structures Monitoring (B2.1.34)

3.5.2.1.40 NSSS Supports

Materials

The materials of construction for the NSSS supports subcomponents are:

- Grout
- High-strength steel
- Lubrite®
- Stainless steel
- Steel

Environment

The NSSS supports subcomponents are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air with borated water leakage

Aging Effects Requiring Management

The following aging effects, associated with the NSSS supports subcomponents, require management:

- Cracking
- Loss of material
- Loss of mechanical function
- Loss of preload
- Reduction in concrete anchor capacity

Aging Management Programs

The following aging management programs manage the aging effects for the NSSS supports subcomponents:

- ASME Section XI, Subsection IWF (B2.1.31)
- Boric Acid Corrosion (B2.1.4)
- Structures Monitoring (B2.1.34)

3.5.2.2 Further Evaluation of Aging Management as Recommended by NUREG-2192

NUREG-2192 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the Subsequent License Renewal Application. For the containment, structures and component supports, those evaluations are addressed in the following sections.

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 Subfoundations

Cracking and distortion due to increased stress levels from settlement could occur in PWR and BWR concrete and steel containments. The existing program relies on ASME Code, Section XI, Subsection IWL to manage these aging effects. Also, reduction of foundation strength and cracking, due to differential settlement and erosion of porous concrete subfoundations could occur in all types of PWR and BWR containments. The existing program relies on the structures monitoring program to manage these aging effects. However, some plants may rely on a dewatering system to lower the site groundwater level. If the plant's current licensing basis (CLB) credits a dewatering system to control settlement, further evaluation is recommended to verify the continued functionality of the dewatering system during the subsequent period of extended operation.

[3.5.1-001] - The Containments are supported on reinforced concrete basemats constructed inside an open cut excavation in rock, with a drainage layer of porous concrete placed between the basemat and the rock. The Containments were initially included in a plant settlement monitoring program; however, after years of monitoring, it was concluded that rock founded structures, which included the Containments, were not settling. This resulted in license amendments, which among other things, removed rock founded structures from the settlement monitoring program (Reference ML013480518). UFSAR Section 3.8.4.5.3 discusses the structures currently monitored for settlement. Accessible concrete components are monitored by the Structures Monitoring (B2.1.34) program for components within the scope of the Structures Monitoring (B2.1.34) program or the ASME Section XI, Subsection IWL (B2.1.30) program for components within the scope of the ASME Section XI, Subsection IWL (B2.1.30) program to confirm the absence of any visible effects due to settlement. Plant operating experience has not identified cracking or distortion associated with settlement.

[3.5.1-002] - UFSAR Section 3.8.2 discusses the Containment foundation design. The Containments are founded on rock. Beneath the Containments, two layers of porous concrete were placed directly on the rock surface. The Containment mat foundation was placed on top of the porous concrete. The porous concrete layers were utilized for construction drainage and were not installed to reduce settlement. A Containment subsurface drainage system, which is within-scope of subsequent license renewal, was installed to reduce the potential for hydrostatic pressure on the liner, but it also is not relied on for settlement control. Accessible concrete components are monitored by the Structures Monitoring (B2.1.34) program or the ASME Section XI, Subsection IWL (B2.1.30) program to confirm the absence to settlement. Plant operating experience has not identified cracking or distortion associated with settlement.

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 portions 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).

[3.5.1-003] - UFSAR Section 3.8.2.1.4.2 discusses high temperature pipe penetrations. Containment penetrations for piping systems carrying thermally hot (over 150°F) fluids include insulation to prevent the temperature of the concrete adjacent to the penetration sleeve from exceeding 200°F. Per UFSAR Section 3.8.2.2 and Technical Specification 3.6.5, the maximum average bulk air temperature inside the Containment is limited to 115°F. Therefore, the Containment concrete will not exceed the ASME Code specified limits of 150°F for general areas and 200°F locally. Plant operating experience has not identified any aging effects for Containment concrete related to elevated temperature. Therefore, the aging effects due to elevated temperatures are not applicable for NAPS, and a plant-specific aging management program or plant-specific enhancements to ASME Section XI, Subsection IWL and/or Structures Monitoring aging management programs are 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).

(1) [3.5.1-005] [3.5.1-035] - The ASME Section XI, Subsection IWE (B2.1.29) program manages aging of the steel liner of the concrete Containment, which includes liner anchors and integral attachments. The 10 CFR Part 50, Appendix J (B2.1.32) program manages loss of leak tightness, loss of sealing, and leakage through Containment to assure that allowable leakage rate limits specified in the Technical Specifications are not exceeded. An evaluation of the acceptability of the inaccessible areas is completed whenever conditions are detected in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. A review of plant operating experience associated with accessible areas from the ASME Section XI, Subsection IWE (B2.1.29) program has primarily identified minor indications of Containment liner corrosion, which have been repaired through the Corrective Action Program. However, in 1999, removal of a blister discovered in the Unit 2 containment liner protective coating revealed a corroded spot under the paint. Subsequent testing confirmed the hole to be through the liner. Removal of a portion of the liner revealed a piece of wood, which had been in contact with the liner. Ultrasonic Testing (UT) thickness readings were made on an extended area on either side of the location. Based on an engineering evaluation of these UT readings, larger sections of the liner were removed, the wood was removed, the concrete was repaired, and the liner was repaired. Repairs and examinations of the repairs were completed prior to the end of the outage. Subsequently, a Type A Integrated Leak Rate Test was successfully performed. There have been other documented instances of foreign materials embedded in Containment concrete; however, none of these other instances have led to corrosion of the Containment liner.

The Containment concrete at NAPS was designed, constructed, and inspected in accordance with ACI and ASTM standards, which provide for a good quality, dense, well-cured, and low permeability concrete. The mix proportions were established in accordance with ACI 301. The air-entraining agent was used in an amount sufficient to entrain three to six percent of air, by volume, of normal-weight concrete. This agent conformed to the requirements of Standard Specification for Air-Entraining Admixtures for Concrete, ASTM C260, when tested in accordance with Standard Method of Testing Air-Entraining Admixtures for Concrete, ASTM C233. Procedural controls ensured quality throughout the batching, mixing, and placement processes. The ASME Section XI, Subsection IWL (B2.1.30) program and the Structures Monitoring (B2.1.34) program identify and manage any cracks in the Containment concrete that could potentially provide a pathway for water to reach inaccessible portions of the steel Containment liner. Crack control was achieved through proper sizing, spacing, and distribution of reinforcing steel in accordance with ACI 318. Therefore, a plant-specific aging management program to manage loss of material due to general, pitting and crevice corrosion for steel elements in inaccessible areas is not required.

(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).

(2) Not applicable - BWR only.

(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).

(3) Not applicable - BWR only.

3.5.2.2.1.4 Loss of Prestress Due to Relaxation, Shrinkage, Creep, and Elevated Temperature

Loss of prestress forces due to relaxation, shrinkage, creep, and elevated temperature for PWR prestressed concrete containments and BWR Mark II prestressed concrete containments is a time-limited aging analysis (TLAA) as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The evaluation of this TLAA is addressed in Section 4.5, "Concrete Containment Unbonded Tendon Pre-stress Analysis," and/or Section 4.7 "Other Plant-Specific Time-Limited Aging Analyses," of this SRP-SLR.

[3.5.1-008] - This aging effect is specific to prestressed concrete Containments and is not applicable to NAPS.

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."

[3.5.1-009] - The evaluation of the Containment liner plate fatigue is addressed as a TLAA in SLRA Section 4.6.1, Containment Liner Plate. The evaluation of Containment penetrations fatigue is addressed in SLRA Section 4.6.3, Containment Penetrations Fatigue Analysis.

[3.5.1-027] - NUREG-2191, Section X1.S1, ASME Section XI, Subsection IWE, recommends that steel, stainless steel, and dissimilar metal weld pressure-retaining components that are subject to cyclic loading, but have no CLB fatigue analysis, be monitored for cracking and supplemented with surface examination (or other applicable technique) in addition to visual examination. With the exception of the fuel transfer tube, fuel transfer tube enclosure, fuel transfer tube blind flange, dissimilar metal weld penetrations, and high-temperature piping penetrations, pressure-retaining components that are subject to cyclic loading (with no CLB fatigue analysis) are not managed for cracking with supplemental surface examinations.

NUREG-2191, Section X1.S1, ASME Section XI, Subsection IWE notes that Appendix J leak rate tests capable of detection of cracking may be performed or credited in lieu of the supplemental surface examination. 10 CFR 50 Appendix J Type B local leak rate tests capable of detecting cracking due to cumulative fatigue damage from cyclic loading are performed for the airlocks. Therefore, supplemental surface examinations will not be required for these components.

As noted in NUREG-2192, Section 3.5.2.2.1.5, 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 Containment pressure-retaining components. This approach is used for the other Containment pressure-retaining components subject to cyclic loading for which no CLB fatigue analysis exists.

The containment liner, which includes the equipment hatch, was designed in accordance with ASME Section III, Subsection N-415.1, “Vessels Not Requiring Analysis for Cyclic Operation,” 1968 Edition; and constructed of SA-537 Grade B steel or SA-516 Grade 60. The six conditions in ASME Section III, Subsection N-415.1, were analyzed for the original design, initial license renewal, and subsequent license renewal to determine the need for a detailed fatigue analysis of the containment liner. Results of the analyses determined that a detailed fatigue analysis was not required due to stress fluctuations caused by temperature, pressure, and design earthquake cycles since all six conditions were shown to be satisfied. Therefore, surface examinations are not required for the containment liner.

For design purposes, operating pressure variations were conservatively estimated at 1000 cycles for the original 40-year life. For initial license renewal (60 years), this value was extrapolated to 1500 cycles. The accrued transient cycles as of 11/08/2017 for Unit 1 and Unit 2 were 58 (39.6 years) and 55 (37.2 years), respectively. Even if the existing number of cycles are doubled to project the number of cycles at 80 years of operation, there is sufficient margin in the design cycles to justify retaining 1500 as the number of cycles used to evaluate components for the subsequent period of extended operation (80 years).

For subsequent license renewal, the six conditions in ASME Code, Section III, Subsection N-415.1 were analyzed for penetrations with a maximum operating temperature less than 250°F. The steel penetrations are constructed of SA-516 Grade 60, SA-442 Grade 60, SA-333 Grade 3, SA-333 Grade 6, or SA-350 Grade LF1, and the stainless steel penetrations are constructed of SA-182 Grade F Type 304, SA-312 Type 304, or SA-312 Type 316. Results of these analyses determined that a detailed fatigue analysis was not required due to stress fluctuations caused by temperature, pressure, and design earthquake cycles since all six conditions were shown to be satisfied for each type of material. Therefore, surface examinations are not required for these components.

The ASME Code, Section III, Subsection N-415.1 conditions specified to evaluate cyclic fatigue were applied to each of the materials used in the construction of the containment liner and penetrations. The fatigue waiver analyses provide the technical bases for not requiring that surface examinations be required for these components. The fatigue waiver criteria are individually met for each of these components in terms of their materials of construction.

The ASME Section XI, Subsection IWE (B2.1.29) program, following enhancement, will augment visual examinations with surface examinations (or other applicable technique) to manage cracking in the pressure retaining portions of the fuel transfer tube, fuel transfer tube enclosure, fuel transfer tube blind flange, dissimilar metal weld penetrations, and high-temperature piping penetrations that could be subject to cyclic loading but have no CLB fatigue analysis. Surface examinations will be performed once during each 10-year interval. UFSAR Table 6.2-37 provides a listing of the containment hot piping penetrations (temperature above 250°F).

The existing ASME Section XI, Subsection IWE (B2.1.29) program, following enhancement, and the 10 CFR Part 50, Appendix J (B2.1.32) program are adequate to manage cracking of pressure boundary components that are subject to cyclic loading, but have no CLB fatigue analysis.

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.

[3.5.1-010] - NAPS does not have any stainless steel penetration bellows as part of the Containment pressure boundary; however, stainless steel penetration sleeves, stainless steel penetration flanges, dissimilar metal welds, and stainless steel fuel transfer tube assemblies are integral with the Containments. Plant operating experience has not identified stress corrosion cracking associated with these components. The ASME Section XI, Subsection IWE (B2.1.29) program and the 10 CFR Part 50, Appendix J (B2.1.32) program manage the aging of Containment penetration sleeves, dissimilar metal welds, and fuel transfer tube assemblies. Visual examinations are augmented with surface examinations to manage cracking due to stress corrosion cracking in the Containment pressure retaining portions of the fuel transfer tube, fuel transfer tube enclosure, fuel transfer tube blind flange, dissimilar metal welds, and high-temperature piping penetrations. Surface examinations will be performed once during each 10-year interval.

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 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 SRP-SLR).

[3.5.1-011] - NAPS is located in a severe weathering region, as defined in ASTM C-33. Reinforced concrete for the Containments was designed, constructed, and inspected in accordance with ACI and ASTM standards, which provide for a good quality, dense, well-cured, and low permeability concrete. The concrete mix designs for the Containments contained an air-entraining admixture capable of entraining three to six percent air. Procedural controls ensured quality throughout the batching, mixing, and placement processes. Plant operating experience has not identified any aging effects related to freeze-thaw in accessible areas and the Structures Monitoring (B2.1.34) program and the ASME Section XI, Subsection IWL (B2.1.30) program confirm the absence of aging effects by examining normally inaccessible structural components when scheduled maintenance work and planned plant modifications permit access. Therefore, aging effects due to freeze-thaw in inaccessible areas are not applicable, and a plant-specific aging management program or plant-specific enhancements to ASME Section XI, Subsection IWL and/or Structures Monitoring aging management programs are not required.

3.5.2.2.1.8 Cracking Due to Expansion From Reaction With Aggregates

Cracking due to expansion from reaction with aggregates could occur in inaccessible areas of concrete elements of PWR and BWR concrete and steel containments. The GALL-SLR Report recommends further evaluation to determine 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 SRP-SLR).

[3.5.1-012] - Inspection for Alkali-Silica Reaction (ASR) has been incorporated into the ASME Section XI, Subsection IWL (B2.1.30) program. Augmented inspections for the ASME Section XI, Subsection IWL (B2.1.30) program include examination for pattern cracking with darkened crack edges, water ingress, and misalignment inspections. ASR inspection results are evaluated by the responsible engineer each inspection cycle to identify changes that could be indicative of ASR development. Such indications will be entered into the Corrective Action Program. The ASME Section XI, Subsection IWL (B2.1.30) program requires that evaluation of inspection results includes consideration of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas. Plant operating experience has not identified any indications of ASR for concrete associated with the Containments. Therefore, a plant-specific aging management program or plant-specific enhancements to ASME Section XI, Subsection IWL and/or Structures Monitoring aging management programs for inaccessible areas are not required to manage cracking due to expansion from reaction with aggregates.

3.5.2.2.1.9 Increase in Porosity and Permeability Due to Leaching of Calcium Hydroxide and Carbonation

Increase in porosity and permeability due to leaching of calcium hydroxide and carbonation could occur in inaccessible areas of concrete elements of PWR and BWR concrete and steel containments. Further evaluation is recommended 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 SRP-SLR).

[3.5.1-014] - Reinforced concrete for the Containments was designed, constructed, and inspected in accordance with ACI and ASTM standards, which provide for a good quality, dense, well-cured, and low permeability concrete. Crack control was achieved through proper sizing, spacing, and distribution of reinforcing steel in accordance with ACI 318. Procedural controls ensured quality throughout the batching, mixing, and placement processes. The ASME Section XI, Subsection IWL (B2.1.30) program and the Structures Monitoring (B2.1.34) program identify and manage any cracks in the Containment concrete. The Structures Monitoring (B2.1.34) program and the ASME Section XI, Subsection IWL (B2.1.30) program inspect for evidence of leaching of calcium hydroxide and carbonation in accessible, and normally inaccessible structural components when scheduled maintenance work and planned plant modifications permit access. The Structures Monitoring (B2.1.34) program and the ASME Section XI, Subsection IWL (B2.1.30) program require that evaluation of inspection results includes consideration of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas. Although plant operating experience has identified evidence of leaching of calcium hydroxide and carbonation, it has been determined that the observed leaching did not adversely impact the structural integrity or result in a loss of intended function of in-scope structures. Therefore, a plant-specific aging management program or plant-specific enhancements to ASME Section XI, Subsection IWL and/or Structures Monitoring aging management programs for inaccessible areas to manage the effects of increase in porosity and permeability due to leaching of calcium hydroxide and carbonation are not required.

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 inaccessible areas of these Groups of structures for plants located in moderate to severe weathering conditions to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage these aging effects. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of SRP-SLR).

(1) [3.5.1-042] - Freeze-Thaw - Reinforced concrete structures at NAPS were designed, constructed, and inspected in accordance with ACI and ASTM standards, which provide for a good quality, dense, well-cured, and low permeability concrete. Crack control was achieved through proper sizing, spacing, and distribution of reinforcing steel in accordance with ACI 318. Procedural controls ensured quality throughout the batching, mixing, and placement processes. Reinforced concrete structures that were constructed during initial construction, excluding concrete structures located in the Switchyard, used an air-entraining agent in an amount sufficient to entrain an air content of three to five percent. Reinforced concrete structures that were constructed subsequent to initial construction and structures located in the Switchyard, were designed and constructed consistent with ACI 301 or ACI 318. These ACI codes provide guidance on entraining air into the concrete mix for concrete structures potentially exposed to freezing and thawing conditions.

Plant operating experience has not identified any aging effects related to freeze-thaw in accessible areas and the Structures Monitoring (B2.1.34) program confirms the absence of aging effects by examining normally inaccessible structural components when scheduled maintenance work and planned plant modifications permit access. Therefore, a plant-specific aging management program or plant-specific enhancements to Structures Monitoring aging management program for inaccessible areas are not required to manage loss of material and cracking due to freeze-thaw.

(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 the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage this aging effect. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of SRP-SLR).

(2) [3.5.1-043] - Alkali-Silica Reaction (ASR) - Inspection for ASR at NAPS has been incorporated into the Structures Monitoring (B2.1.34) program. This program includes identification of leading indicator structures to receive an augmented inspection each cycle of the Structures Monitoring (B2.1.34) program. Augmented inspections include examination for pattern cracking with darkened crack edges, water ingress, and misalignment inspections. ASR inspection results are evaluated by the responsible engineer each inspection cycle to identify changes that could be indicative of ASR development. Such indications will be entered into the Corrective Action Program. The Structures Monitoring (B2.1.34) program requires that evaluation of inspection results includes consideration of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas. Plant operating experience has not identified any indications of ASR for the concrete structures at NAPS, except for precast concrete poles that support overhead electrical circuits. The overhead electrical circuits are associated with offsite power supplies relied on to recover from an SBO. There is a design change currently being implemented that either replaces or refurbishes the precast concrete poles. After the design change is implemented, only three precast concrete poles, which are adjacent to the Turbine Building, will remain. The design change will reinforce these three precast concrete poles with a carbon fiber polymer wrap, which provides confinement and strengthening to the poles, and will minimize future ASR induced expansion. The precast concrete poles were fabricated offsite and their concrete is not representative of the concrete used in other structures (i.e., the ASR operating experience associated with the precast concrete poles is not indicative of the potential for ASR in other concrete structures at NAPS). Therefore, a plant-specific aging management program or plant-specific enhancements to Structures Monitoring aging management program for inaccessible areas are not required to manage cracking due to expansion from reaction with aggregates.

(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 subfoundations 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.

(3) [3.5.1-044] [3.5.1-046] - Settlement - The settlement monitoring program is described in UFSAR Section 3.8.4.5.3. At intervals defined in the Technical Requirements Manual, structures at the Service Water Reservoir and at the main plant, including the Service Water Pump House, Service Water Valve House, Service Water Tie-in Vault, Service Building, and Main Steam Valve House, are monitored for settlement. The structures and components which are included in the settlement monitoring program are listed in Table 3.8-15 of the UFSAR. Accessible concrete components of soil founded structures, including those listed in Table 3.8-15 of the UFSAR, are monitored by the Structures Monitoring (B2.1.34) program to confirm the absence of any visible effects due to settlement. Plant operating experience has not identified cracking or distortion associated with settlement.

Porous concrete was not used for structure subfoundations at NAPS, other than below the Containment basemats, which is evaluated previously. Additionally, there are no dewatering systems that are relied on for settlement control.

(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 to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, 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 SRPSLR).

(4) [3.5.1-047] - Leaching - Reinforced concrete structures at NAPS were designed, constructed, and inspected in accordance with ACI and ASTM standards, which provide for a good quality, dense, well-cured, and low permeability concrete. Procedural controls ensured quality throughout the batching, mixing, and placement processes. The Structures Monitoring (B2.1.34) program identifies and manages any cracks in the concrete structures. Additionally, the Structures Monitoring (B2.1.34) program inspects for evidence of leaching of calcium hydroxide and carbonation in accessible, and normally inaccessible structural components when scheduled maintenance work and planned plant modifications permit access. The Structures Monitoring (B2.1.34) program requires that evaluation of inspection results includes consideration of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas. Although plant operating experience has identified evidence of leaching of calcium hydroxide and carbonation, it has been determined that the observed leaching did not adversely impact the structural integrity or result in a loss of intended function of the associated concrete structures. Therefore, a plant-specific aging management program or plant-specific enhancements to Structures Monitoring aging management program for inaccessible areas to manage the effects of increase in porosity and permeability due to leaching of calcium hydroxide and carbonation are not required.

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 degrees Celsius (150 degrees Fahrenheit) except for local areas, which are allowed to have increased temperatures not to exceed 93 degrees Celsius (200 degrees Fahrenheit). Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage these aging effects if any portion of the safety-related and other concrete structures exceeds 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. The acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of SRP-SLR).

[3.5.1-048] - UFSAR Section 9.1.3.1 discusses the design basis for the fuel pit cooling. The temperature of the spent fuel pit water is maintained below 140°F during the most limiting condition for normal core offload, which is a planned full core offload following refueling of the other unit. The temperature of the fuel pit water is maintained below 170°F during the most limiting condition for abnormal core offload, which is an unplanned full core offload following back-to-back refueling of both units. Per UFSAR Section 9.1.3.5, instrumentation provided gives local indication in the Fuel Building and the Auxiliary Building, and remote indications and alarms in the main control room for spent fuel pit temperature above 140°F and above 170°F. Therefore, the concrete temperature will not exceed a temperature of 140°F except during the rare and short-term event of an abnormal core offload, during which the temperature of the concrete in some areas may reach 170°F.

The maximum general area air temperature in the other structures is less than 150°F. The maximum temperature in the upper elevation of Main Steam Valve House can potentially be as high as 160°F in specific areas. The maximum bulk air temperature is lower than this temperature, and this maximum temperature is not sustained. Hot pipe penetrations in other structures may be subject to temperatures higher than 150°F, but not greater than 200°F.

No other issues related to elevated temperatures affecting concrete structures exposed to air have been identified. Therefore, the aging effects due to elevated temperatures are not applicable for NAPS, and a plant-specific aging management program or plant-specific enhancements to Structures Monitoring aging management program are not required.

3.5.2.2.2.3 Aging Management of Inaccessible Areas for Group 6 Structures

Further evaluation is recommended for inaccessible areas of certain Group 6 structure/aging effect combinations as identified below, whether or not they are covered by inspections in accordance with the GALL-SLR Report, AMP XI.S7, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," or Federal Energy Regulatory Commission (FERC)/U.S. Army Corp of Engineers dam inspection and maintenance procedures.

(1) Loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas of Group 6 structures. Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage these aging effects of this aging effects for inaccessible areas for plants located in moderate to severe weathering conditions. Acceptance criteria are described in BTP RLSB-1 (Appendix A1 of SRP-SLR).

(1) [3.5.1-049] - Freeze-Thaw - Reinforced concrete for water-control structures (Group 6) was designed, constructed, and inspected in accordance with ACI and ASTM standards, which provide for a good quality, dense, well-cured, and low permeability concrete. Procedural controls ensured quality throughout the batching, mixing, and placement processes. The concrete mix designs for water-control structures (Group 6) constructed during initial construction contained an air-entraining agent capable of entraining three to five percent air. The concrete mix designs for water-control structures (Group 6) constructed subsequent to initial construction contain an air-entraining agent for freeze-thaw protection consistent with ACI 301 or ACI 318. Plant operating experience has not identified any aging effects related to freeze-thaw in accessible areas and the Structures Monitoring (B2.1.34) program confirms the absence of aging effects by examining normally inaccessible structural components when scheduled maintenance work and planned plant modifications permit access. Therefore, aging effects due to freeze-thaw in inaccessible areas are not applicable, and a plant-specific aging management program or plant-specific enhancements to Structures Monitoring aging management program are not required.

(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 the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, to manage this aging effect. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of SRP-SLR).

(2) [3.5.1-050] - Alkali-Silica Reaction (ASR) - Inspection for Alkali-Silica Reaction (ASR) has been incorporated into the Structures Monitoring (B2.1.34) program, which includes water-control structures (Group 6). This program includes identification of leading indicator structures to receive an augmented inspection each cycle of the Structures Monitoring (B2.1.34) program. Augmented inspections include examination for pattern cracking with darkened crack edges, water ingress, and misalignment inspections. ASR inspection results are evaluated by the responsible engineer each inspection cycle to identify changes that could be indicative of ASR development. Such indications will be entered into the Corrective Action Program. The Structures Monitoring (B2.1.34) program requires that evaluation of inspection results includes consideration of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas. Plant operating experience has not identified any indications of ASR for the concrete structures associated with the water-control structures (Group 6). Therefore, a plant-specific aging management program or plant-specific enhancements to Structures Monitoring aging management program for inaccessible areas are not required to manage cracking due to expansion from reaction with aggregates.

(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 to determine the need for a plant-specific AMP or plant-specific enhancements to Structures Monitoring AMP, 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 SRP-SLR).

(3) [3.5.1-051] - Leaching - Water-control structures (Group 6) were designed, constructed, and inspected in accordance with ACI and ASTM standards, which provide for a good quality, dense, well-cured, and low permeability concrete. Procedural controls ensured quality throughout the batching, mixing, and placement processes. The Structures Monitoring (B2.1.34) program identifies and manages any cracks in the concrete structures. Additionally, the Structures Monitoring (B2.1.34) program inspects for evidence of leaching of calcium hydroxide and carbonation in accessible, and normally inaccessible structural components when scheduled maintenance work and planned plant modifications permit access. The Structures Monitoring (B2.1.34) program requires that evaluation of inspection results includes consideration of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas. Although plant operating experience has identified evidence of leaching of calcium hydroxide and carbonation, it has been determined that the observed leaching did not adversely impact the structural integrity or result in a loss of intended function of the associated concrete structures. Therefore, a plant-specific aging management program or plant-specific enhancements to Structures Monitoring aging management program for inaccessible areas to manage the effects of increase in porosity and permeability due to leaching of calcium hydroxide and carbonation are not required.

3.5.2.2.2.4 Cracking Due to Stress Corrosion Cracking, and Loss of Material Due to Pitting and Crevice Corrosion

Cracking due to SSC and loss of material due to pitting and crevice corrosion could occur in: (a) Group 7 and 8 SS tank liners exposed to standing water; and (b) SS and aluminum alloy support members; welds; bolted connections; or support anchorage to building structure exposed to air or condensation (see SRP SLR Sections 3.2.2.2.2, 3.2.2.2.4, 3.2.2.2.8, and 3.2.2.2.10 for background information).

For Group 7 and 8 SS tank liners exposed to standing water, further evaluation is recommended of plant-specific programs to manage these aging effects. The acceptance criteria are described in BTP RLSB 1 (Appendix A.1 of this SRP SLR).

For SS and aluminum alloy support members; welds; bolted connections; support anchorage to building structure exposed to air or condensation, the plant specific OE and condition of the SS and aluminum alloy components are evaluated to determine if the plant specific air or condensation environments are aggressive enough to result in loss of material or cracking after prolonged exposure. The aging effects of loss of material and cracking in SS and aluminum alloy components is not applicable and does not require management if: (a) the plant specific OE does not reveal a history of pitting or crevice corrosion or cracking and (b) a one-time inspection demonstrates that the aging effects are not occurring or that an aging effect is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant specific OE review in the SLRA. Visual inspections conducted in accordance with GALL-SLR Report AMP XI.M32, "One Time Inspection," are an acceptable method to demonstrate that the aging effects are not occurring at a rate that affects the intended function of the components. One-time inspections are conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32. If loss of material or cracking has occurred and is sufficient to potentially affect the intended function of SS or aluminum alloy support members; welds; bolted connections; or support anchorage to building structure, either: (a) enhancing the applicable AMP (i.e., GALL-SLR Report AMP XI.S3, "ASME Code, 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.

[3.5.1-052] - There are no stainless steel tank liners that are within the scope of subsequent license renewal. Stainless steel components in the Containments (Containment sump liners) are exposed to standing water and are aligned to this item. Plant-specific operating experience has not identified loss of material due to pitting or crevice corrosion, or cracking due to SCC for the stainless steel associated with the Containment sump liners. The plant specific aging management program used to manage the Containment sump liners for cracking due to SCC, and loss of material due to pitting and crevice corrosion is included within the Structures Monitoring (B2.1.34) program.

[3.5.1-099] - Plant-specific OE has identified pitting or crevice corrosion or cracking for stainless steel piping components exposed to air or condensation in an underground environment (see Further Evaluation 3.4.2.2.2. The ASME Section XI, Subsection IWF (B2.1.31) program will manage the aging of stainless steel component supports to ensure that these components continue to perform their intended functions during the subsequent period of extended operation. There are no aluminum support components that are within the scope of the ASME Section XI, Subsection IWF (B2.1.31) program.

[3.5.1-100] - Plant-specific OE has identified pitting or crevice corrosion or cracking for stainless steel piping components exposed to air or condensation in an underground environment (see Further Evaluation 3.4.2.2.2. The Structures Monitoring (B2.1.34) program will manage the aging of stainless steel and aluminum alloy components to ensure that these components continue to perform their intended functions during the subsequent period of extended operation. In addition to Structures and Component Supports, stainless steel components in Auxiliary Systems (materials handling) are aligned to this row with management by the Structures Monitoring (B2.1.34) program.

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.

[3.5.1-053] - There are no TLAAs associated with component support members, anchor bolts, and welds for Groups B1.1 and B1.2 component supports. Group B1.3 component supports are associated with BWRs; therefore, not applicable.

3.5.2.2.2.6 Reduction of Strength and Mechanical Properties of Concrete Due to Irradiation

Reduction of strength, loss of mechanical properties, and cracking due to irradiation could occur in PWR and BWR Group 4 concrete structures that are exposed to high levels of neutron and gamma radiation. These structures include the reactor (primary/biological) shield wall, the sacrificial shield wall, and the reactor vessel support/pedestal structure. Data related to the effects and significance of neutron and gamma radiation on concrete mechanical and physical properties is limited, especially for conditions (dose, temperature, etc.) representative of light water reactor (LWR) plants. However, based on literature review of existing research, radiation fluence limits of 1 x 10^{19} *neutrons/cm*^{2} *neutron radiation and 1 x* 10^8 *Gy (1 x* 10^{10} *rad) gamma dose are considered conservative radiation exposure levels beyond which concrete material properties may begin to degrade markedly (Ref. 17, 18, 19).*

Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to selected existing AMPs to manage the 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 that could affect 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).

[3.5.1-097] - The configuration of the reactor vessel steel supports and adjacent concrete biological shield (CBS) wall (also known as the primary shield wall) are similar between the North Anna Power Station (NAPS) and Surry Power Station (SPS). The analytical methods used at SPS to estimate neutron and gamma radiation damage to the CBS wall and the reactor vessel steel supports were determined to be acceptable as documented in the “Safety Evaluation Report Related to the Subsequent License Renewal of Surry Power Station, Units 1 and 2,” (ADAMS Accession No. ML20052F523). Thus, the analytical methods used to evaluate CBS wall and reactor vessel steel supports at SPS were used to evaluate the NAPS CBS wall and reactor vessel steel supports for the subsequent period of extended operation.

The following information describes the general configuration of the reactor vessel steel supports and adjacent CBS wall, the analytical methods used to determine the neutron and gamma radiation environment and the analytical results of the radiation impact to the reactor vessel steel supports and CBS wall.

Reactor Vessel Supports and Concrete Biological Shield Wall Configuration

The reactor vessel is supported at each of the six primary loop nozzles by a sliding foot assembly (AISI 4330 modified). The bottom of each sliding foot support assembly is mounted to the top of the neutron shield tank (NST). The NST surrounds the reactor vessel and is enclosed by the CBS wall. The NST is a double-walled cylindrical steel structure that is filled with corrosion-inhibited water that was designed to limit gamma and neutron damage to the CBS wall. The inner shell of the NST extends continuously past the bottom of the reactor vessel to the basemat inside of Containment. Thus, vertical loads from the reactor vessel are transferred by the sliding feet through the NST to the Containment basemat with no vertical loading on the CBS wall. Overturning moments and horizontal forces are resisted by the CBS wall through a layer of grout, which fills the upper portion of the two-inch gap between the NST and the surrounding CBS wall.

Concrete Biological Shield Wall Evaluation

Two analytical models investigate the potential impact of neutron and gamma radiation to the CBS wall. The first model, developed by Westinghouse, was used to assess the neutron and gamma radiation within the CBS wall. The second model, developed by the Electric Power Research Institute (EPRI), assesses the neutron and gamma radiation and potential gamma heating of the CBS wall. Dominion Energy elected to use the Westinghouse model for assessment of the neutron and gamma radiation and the EPRI model for assessment of gamma heating of the CBS wall.

To determine the neutron and gamma radiation environment within the CBS wall, Westinghouse performed a plant-specific analysis, which used an amended version of the RG 1.190-compliant Westinghouse model used to predict the reactor vessel fluence for reactor vessel integrity evaluations. This model, which is documented in LTR-REA-20-2, “North Anna Unit 1 and Unit 2 Reactor Cavity Concrete Neutron Fluence and Gamma Dose”, is based on NRC-approved Westinghouse reactor vessel fluence analysis methods, as documented in WCAP-14040-A, Revision 4, “Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves”. For the plant-specific analyses, Westinghouse performed discrete ordinates radiation transport analysis calculations. The discrete ordinates radiation transport calculations were performed on a fuel-cycle-specific basis to determine the neutron and gamma environment within the reactor, cavity, and CBS wall geometry. These plant-specific forward transport calculations were carried out using the two-dimensional/one dimensional fluence rate synthesis methodology described in Regulatory Guide 1.190 and WCAP-14040-A, Revision 4.

The transport calculations were performed using the two-dimensional discrete ordinates code, DORT, and the BUGLE-96 cross-section library. The model extends radially from the centerline of the reactor core out to a location interior to the CBS wall, and over an axial span of -338.525 centimeters to +343.460 centimeters with respect to the midplane of the active core indexed at 0 centimeters. The models of the reactor (and cavity) geometry include the region above the NST, but do not extend to the bottom of the NST. Fast neutron (E > 0.1 MeV) fluences and gamma doses tend to decrease with distance as neutrons and gammas travel away from the core at elevations below the active fuel. Since the distance between the bottom of the NST and the bottom of the active fuel is approximately 266 centimeters greater than the distance between the top of the NST and the top of the active fuel, the neutron fluence and gamma dose of the CBS wall in the lower regions that are not included in the reactor model are considered to be bounded by the neutron fluence and gamma dose in the region above the NST.

The maximum fast neutron (E > 0.1 MeV) fluences and gamma doses at the CBS wall inner surface occur at an azimuthal angle of 0° and at a location above the NST. The maximum fast neutron (E > 0.1 MeV) fluences and gamma doses at the CBS wall determined by Westinghouse are as follows:

- For NAPS Unit 1, the maximum neutron fluence at 72 EFPY for the CBS wall surface is 3.09E18 n/cm^2 (E > 0.1 MeV). For NAPS Unit 2, the maximum neutron fluence at 72 EFPY for the CBS wall surface is 3.15E18 n/cm^2 (E > 0.1 MeV). These values are below the SLR-SRP threshold limit of 1E19 n/cm^2 for fast neutron fluence (E > 0.1 MeV). For NAPS Unit 1 and Unit 2, the location of the maximum neutron fluence is approximately 288 centimeters above the core midplane.
- For NAPS Unit 1, the maximum gamma surface dose at 72 EFPY for the CBS wall is 2.90E6 Gy. For NAPS Unit 2, the maximum gamma surface dose at 72 EFPY for the CBS wall is 2.93E6 Gy. These values are below the SLR-SRP threshold limit of 1E8 Gy. For NAPS Unit 1 and Unit 2, the location of the maximum gamma dose is approximately 282 centimeters above the core midplane.

EPRI Report 3002013051, “Irradiation Damage of the Concrete Biological Shield that Utilizes a Neutron Shield Tank,” was utilized to access the potential impact of gamma heating of the CBS wall. EPRI Report 3002013051 is a generic technical report based on a 3-loop PWR reactor design (specific example plant utilized being SPS) baselined on H.B. Robinson transport analyses performed by Oak Ridge National Laboratories and TransWare for 72 effective full-power years (EFPY). Since the example plant studied was SPS and the configuration of the NSTs and adjacent CBS walls are similar between NAPS and SPS, the results of EPRI Report 3002013051 are applicable for NAPS. Additionally, based on Westinghouse Letter Reports LTR-REA-18-88 (SPS) and LTR-REA-20-2 (NAPS), the maximum gamma dose at the CBS wall at the end of the subsequent period of extended operation are approximately the same. Therefore, the generic assessment of gamma heating is considered applicable to the CBS wall at NAPS.

Based on EPRI Report 3002013051, it was determined that the maximum concrete temperature of the CBS wall due to gamma heating is 125.1°F and below the acceptable long-term temperature limit of 150°F for general areas and 200°F for local areas specified in ACI 349.

In summary, the neutron and gamma radiation exposure levels and gamma heating of the CBS wall at the end of the subsequent period of extended operation will be less than the radiation fluence limits of 1E19 neutrons/cm^2 neutron fluence and 1E8 Gy (1E10 rad) gamma dose. Additionally, the maximum temperature in the CBS wall concrete, including radiation-induced heating, will be less than the acceptable long-term temperature limit of 150°F for general areas and 200°F for local areas.

In addition to the above conclusions, accessible portions of the CBS wall are periodically inspected by the Structures Monitoring (B2.1.34) program. A review of operating experience over the past ten years has not identified degradation due to irradiation for the CBS wall. Therefore, a plant-specific aging management program to manage the effects of concrete irradiation is not required.

<u>Reactor Vessel Steel Support Evaluation</u>

NUREG-1509, “Radiation Effects on Reactor Pressure Vessel Supports,” provides a screening evaluation approach to evaluate the loss of fracture toughness of reactor vessel steel supports. The screening evaluation includes the following criteria for assessing the structural integrity of reactor vessel steel supports:

- The initial nil ductility temperature (NDT) of the reactor vessel supports is well below the minimum operating temperature.
- The radiation exposure at the supports is low.
- The peak tensile stresses are 6 ksi, or less.

The NAPS reactor vessel steel supports were compared to the screening criteria in NUREG-1509 to assess the structural integrity. Although the initial NDT of the reactor vessel steel supports was below the minimum operating temperature, the other two screening criteria for radiation exposure and peak tensile stresses (i.e., below 6 ksi or less), were not met as described below:

Radiation Exposure

LTR-REA-20-3, "North Anna Unit 1 and Unit 2 Neutron Shield Tank (NST) Neutron Fluence" Rev. 0-A provides projections of radiation exposure for the NSTs at 80 years (72 EFPY) of plant operation. For NAPS Unit 1, the fluence at 72 EFPY adjacent to the core region is projected to be 3.94E19 n/cm^2 (E > 0.1 MeV) and 3.91E18 n/cm^2 (E > 1.0 MeV). For NAPS Unit 2, the fluence at 72 EFPY adjacent to the core region is projected to be 4E19 n/cm^2 (E > 0.1 MeV) and 3.97E18 n/cm^2 (E > 1.0 MeV). By contrast, the projected fluence values at the top of the NAPS Unit 1 and Unit 2 NSTs near the reactor vessel nozzles are approximately one order of magnitude lower. Typically, reactor vessel integrity fluence values greater than 1.0E17 n/cm^2 (E > 1.0 MeV) require a shift to be added to the initial NDT. While the NST is not a pressure vessel, based upon this consideration, the screening criterion of low radiation exposure at the reactor vessel steel supports are conservatively considered as not satisfied.

Peak Tensile Stress

The peak tensile stresses due to deadweight, DBE seismic, and LOCA loads were determined to be at the NST shell at reactor vessel sliding foot support (12.44 ksi) and the NST inner shell (7.93) ksi. Thus, both regions of the NST have tensile loads greater than 6 ksi thus, the screening criterion of peak tensile stresses of 6 ksi or less is not satisfied.

In addition to the screening criteria, NUREG-1509 also provides an option to evaluate the loss of fracture toughness of reactor vessel steel supports using a fracture mechanics evaluation. A fracture mechanics evaluation consistent with the methodology provided in NUREG-1509 was utilized in the evaluation of the SPS reactor vessel steel supports. The fracture mechanics evaluation, accepted by the NRC Safety Evaluation for Surry SLR (ADAMS Accession No. ML20052F523), was based on a methodology detailed in Project Topical Report (PTR), "Reactor Vessel Support for Unit No. 1 Surry Power Station, Life Extension Evaluation of the Reactor Vessel Support, including Appendix 3, Resistance to Brittle Fracture of the Neutron Shield Tank Materials." In support of plants considering initial license renewal, the PTR was developed by Stone and Webster in 1986 for Virginia Power, EPRI, US Department of Energy, and the Westinghouse Owners Group to address the potential loss of fracture toughness due to neutron irradiation embrittlement. The methodology used to evaluate the structural integrity of the SPS Unit 1 NST compared the applied stresses for the area of the SPS Unit 1 NST subject to high neutron fluence (developed in a separate calculation by Stone and Webster) to critical stresses derived from the fracture mechanics evaluation.

Due to the similarities of the reactor vessel steel supports between SPS and NAPS, the fracture mechanics approach used for SPS (based on the PTR for SPS Unit 1) was utilized in the NAPS evaluation. An engineering review confirmed that the configuration, material properties, and heat treatment for the NAPS Unit 1, NAPS Unit 2, and SPS Unit 1 NSTs are similar and applicable for this evaluation.

The loading conditions used to calculate stresses for the fracture mechanics evaluation were deadweight, design basis earthquake accelerations, and thrust forces from pipe ruptures of reactor coolant branch lines. These loading conditions are consistent with the loading conditions used in the current design basis calculations. The design loads were combined consistent with the current design basis calculations and the controlling load combination was as follows:

Design Load = Deadweight + $[(\text{DBE Seismic})^2 + (\text{LOCA})^2]^{1/2}$

Notes:

1. DBE Seismic = forces due to design basis earthquake accelerations
2. LOCA = thrust forces from pipe ruptures of reactor coolant branch lines
3. Unlike SPS, the NAPS loss of coolant accident (LOCA) loads do not credit larger break opening times of the branch lines. It is expected that refined analysis of the NAPS reactor coolant piping crediting longer break opening times, as was done for SPS, would significantly reduce the magnitude of LOCA loads.

The tensile stresses of 7.93 ksi (for the NST inner shell) and 12.44 ksi (for the NST shell at reactor vessel sliding foot support) have been evaluated using fracture mechanics.

The analytical approach used in the fracture mechanics evaluation outlined in the PTR involves back calculation of the critical stress, S_m, as a function of plane strain fracture toughness. That is, if the applied stress is less than the S_m there will be no brittle fracture; brittle fracture will occur if the stress is equal to or greater than S_m.

The applied stresses for the area of the NST subject to high neutron fluence (shown above) are compared to critical stresses derived from the fracture toughness evaluation in order to demonstrate structural integrity of the NST.

For NAPS, the fracture mechanics evaluation is based upon the use of American Society of Mechanical Engineers (ASME) Code, Section XI, Figure A-4200-1, which plots the fracture toughness, K_{Ic} and K_{Ia} (synonymous with K_{IR}). K_{Ic} and K_{Ia} represent critical values of the stress intensity factor K_I. K_{Ia} is based on the lower bound of crack arrest critical K_I values measured as a function of temperature. K_{Ic} is based on the lower bound of static initiation critical K_I values measured as a function of temperature.

Per NUREG-1509, Section 4.3.4.1 it is permissible to use K_{Ic} in lieu of K_{IR} when there is information available for the material toughness. For the NAPS NSTs, the NDT (nil-ductility temperature, which is synonymous to RT_{NDT} per NUREG-1509) of the ASTM-A516 Grade 60 carbon steel plate used for the inner shell of the tank is -40°F or better and -20°F or better at other locations of the NST. Therefore, the most limiting K_{Ic} value is selected by using the formula for K_{Ic} in Section III and Section XI, Appendix G

$$K_{Ic} = 33.2 + 20.734\exp[0.02(T-RT_{NDT})], \ (\text{ksi-in}^{0.5})$$

A minimum toughness value of 33.2 ksi√in from the K_{Ic} curve is used for assessment of the NAPS NSTs.

Two cases have been selected to bound the material properties:

- Case 1 uses the code minimum yield stress value of 32 ksi, and
- Case 2 uses a higher yield stress of 52 ksi. NUREG-1509 (Section 4.7) assumes an approximate radiation yield stress increase of 20 ksi. Therefore, a 20 ksi increase in yield stress is being added to the code minimum yield stress value of 32 ksi for embrittlement damage that will increase the unirradiated yield strength due to irradiation. These yield point values were chosen to bound the code minimum yield stress and compensate for the potential impact of irradiation during plant operation

Since the bounding lower toughness value of 33.2 ksi√in from the K_{Ic} curve is used in the fracture mechanics evaluation, the use of two yield stress values of 32 ksi and 52 ksi was considered adequate in the fracture mechanics evaluation without further adjustment to account for changes in yield strength due to irradiation.

In the fracture mechanics evaluation, two flaw postulated cases are considered for the NAPS NSTs - Case 1 evaluates both a through wall flaw and surface flaw using a yield stress of 32 ksi, and Case 2 evaluates both a through wall flaw and surface flaw using a yield stress of 52 ksi.

The results of the fracture mechanics evaluation for the NAPS NSTs is shown in Table 1.

Table 1: NAPS NSTs - Critical Stress for Postulated Through-wall and Surface Flaw Cases

Case No.	Yield Stress (ksi)	Critical Stress (S_m in ksi)	
		Through-Wall Flaw Case (ksi)	Surface Flaw Case (ksi)
1	32	18.4	36.8
2	52	15.8	36.0

Review of the configuration, loads, heat treatment, and NDT values confirm that the applied loads from a design basis accident are below the critical stress values calculated based upon using the methodology outlined in Appendix 3 of the PTR for a postulated surface flaw and postulated through wall flaw. The material property information using the certified material test reports for Unit 1 and 2 NSTs illustrates margin relative to the actual stresses. The maximum applied tensile stress during a design basis event is approximately 12.44 ksi near the reactor vessel sliding foot assemblies and 7.93 ksi at the NST inner shell. The maximum applied tensile stresses during a design basis event are less than the allowable critical stresses for the through-wall flaw case and the surface flaw case; therefore, brittle fracture will not occur. There is additional unquantified margin in the evaluation of the reactor vessel steel support assembly in that the projected fluence values near the reactor vessel sliding foot assemblies are approximately one order of magnitude lower than the projected fluence values for the NST inner shell. These projected maximum applied tensile stress values are lower than the calculated minimum S_m values. Therefore, the fracture mechanics evaluation and fluence evaluations provide reasonable assurance that loss of fracture toughness due to irradiation will not affect the NST structural integrity during the subsequent period of extended operation.

The Structures Monitoring (B2.1.34) program and the External Surfaces Monitoring of Mechanical Components (B2.1.23) program manages aging of the external surfaces of the NST, including the NST support skirt. The Structures Monitoring (B2.1.34) program will be enhanced to specify that evaluations of NST findings consider its structural support function for the reactor vessel.

The ASME Section XI, Subsection IWF (B2.1.31) program manages aging of the sliding foot assemblies. Similar to SPS, Lubrite® lubricant is used with the NAPS reactor vessel sliding foot assemblies. Using the same basis that was used for evaluating the Lubrite® associated with the SPS reactor vessel sliding supports (ADAMS Accession No. ML19204A357), it was concluded that aging effects due to temperature or radiation for Lubrite® would not be significant. As noted in the Final Safety Evaluation Report for SPS SLR (ADAMS Accession No. ML20052F523), the NRC has reasonable assurance that the Lubrite® would not lose its lubricating function due to neutron fluence effects during the subsequent period of extended operation. The potential aging effect resulting from Lubrite® degradation due to irradiation would be loss of mechanical function. Loss of mechanical function of the Lubrite® sliding surfaces is an aging effect that is being managed by the ASME Section XI, Subsection IWF (B2.1.31) program. A review of the NAPS ASME Section XI, Subsection IWF operating experience has not identified the loss of intended function for the reactor vessel support sliding foot assemblies.

Loss of material of the NST internal surface is managed by the Closed Treated Water Systems (B2.1.12) program. The program consists of water treatment, chemical testing, and inspections to determine the presence or extent of degradation. Each refueling outage includes a chemical analysis of a representative sample to detect potential loss of material. Neutron shield cooling water samples are examined for concentrations of iron as a byproduct of NST internal steel corrosion, for chloride and fluoride ions that assist corrosion, and for chromates that inhibit corrosion. Chloride and fluoride concentrations remain far below the procedural limits, whereas chromate concentration for passivation of steel at both NSTs over time remained above minimum station requirements. Iron concentrations tracking is used as a diagnostic parameter of active NST internal corrosion and remains at the instrumentation detection level.

A review of plant-specific operating experience has not identified degradation due to irradiation aging effects with the reactor vessel steel supports or the reactor vessel sliding foot assemblies. A plant-specific aging management program is not required to manage: (1) loss of fracture toughness due to irradiation embrittlement or (2) loss of mechanical or other functions due to irradiation. The identified aging effects will be adequately managed by the credited aging management programs so the intended functions of the reactor vessel steel support assemblies will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

3.5.2.2.3 Quality Assurance for Aging Management of Nonsafety-Related Components

Quality Assurance provisions applicable to subsequent license renewal are discussed in Appendix B1.3, Quality Assurance Program and Administrative Controls.

3.5.2.2.4 Ongoing Review of Operating Experience

The operating experience process and acceptance criteria are described in Appendix B1.4, Operating Experience.

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Results Tables: Containment, Structures and Component Supports

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

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-001	Concrete: dome; wall; basemat; ring girders; buttresses, concrete elements, all	Cracking and distortion due to increased stress levels from settlement	AMP XI.S2, ASME Section XI, Subsection IWL, and/or AMP XI.S6, Structures Monitoring	Yes (SRP-SLR Section 3.5.2.2.1.1)	Consistent with NUREG-2191. See further evaluation 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)	Consistent with NUREG-2191. See further evaluation in Section 3.5.2.2.1.1.
3.5.1-003	Concrete: dome; wall; basemat; ring girders; buttresses, concrete: containment; wall; basemat, concrete: basemat, concrete fill-in annulus	Reduction of strength and modulus of elasticity due to elevated temperature (>150°F general; >200°F local)	Plant-specific aging management program, 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. Temperature thresholds for reduction of strength and modulus of elasticity are not exceeded. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.5.2.2.1.2.
3.5.1-004	Steel elements (inaccessible areas): drywell shell; drywell head	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	Yes (SRP-SLR Section 3.5.2.2.1.3.1)	Not applicable - BWR only.
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, crevice corrosion	AMP XI.S1, ASME Section XI, Subsection IWE, and AMP XI.S4, 10 CFR Part 50, Appendix J	Yes (SRP-SLR Section 3.5.2.2.1.3.1)	Consistent with NUREG-2191. See further evaluation in Section 3.5.2.2.1.3.1.

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

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-006	Steel elements: torus shell	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	Yes (SRP-SLR Section 3.5.2.2.1.3.2)	Not applicable - BWR only.
3.5.1-007	Steel elements: torus ring girders; downcomers;, Steel elements: suppression chamber shell (interior surface)	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, ASME Section XI, Subsection IWE	Yes (SRP-SLR Section 3.5.2.2.1.3.3)	Not applicable - BWR only.
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 Time-Limited Aging Analyses	Yes (SRP-SLR Section 3.5.2.2.1.4)	Not applicable. NAPS does not have prestressed Containment structures. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.5.2.2.1.4.
3.5.1-009	Metal liner, metal plate, personnel airlock, equipment hatch, 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 cyclic loading (Only if CLB fatigue analysis exists)	TLAA, SRP-SLR Section 4.6, Containment Liner Plate and Penetration Fatigue Analysis	Yes (SRP-SLR Section 3.5.2.2.1.5)	Consistent with NUREG-2191. See further evaluation in Section 3.5.2.2.1.5.
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. In addition to Containment Structure, components in Auxiliary Systems (fuel handling) are aligned to this row. See further evaluation in Section 3.5.2.2.1.6.

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

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-011	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Plant-specific aging management program, 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. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.5.2.2.1.7.
3.5.1-012	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, containment, concrete fill-in annulus	Cracking due to expansion from reaction with aggregates	Plant-specific aging management program, 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 aging management program used to manage cracking of Containment concrete elements (inaccessible areas) is the ASME Section XI, Subsection IWL (B2.1.30) program. See further evaluation in Section 3.5.2.2.1.8.
3.5.1-014	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, containment	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Plant-specific aging management program, 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)	Not applicable. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.5.2.2.1.9.
3.5.1-016	Concrete (accessible areas): basemat, concrete: containment; wall	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. Increase in porosity and permeability; cracking; loss of material (spalling, scaling) of Containment concrete elements (accessible areas) is managed by the ASME Section XI, Subsection IWL (B2.1.30) program.
3.5.1-018	Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses	Loss of material (spalling, scaling) and cracking due to freeze-thaw	AMP XI.S2, ASME Section XI, Subsection IWL, and/or AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191. Loss of material (spalling, scaling) and cracking of Containment concrete elements is managed by the ASME Section XI, Subsection IWL (B2.1.30) program.

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

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-019	Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses, containment; concrete fill-in annulus	Cracking due to expansion from reaction with aggregates	AMP XI.S2, ASME Section XI, Subsection IWL, and/or AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191. Cracking of Containment concrete elements (accessible areas) is managed by the ASME Section XI, Subsection IWL (B2.1.30) program.
3.5.1-020	Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses, containment	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	AMP XI.S2, ASME Section XI, Subsection IWL	No	Consistent with NUREG-2191.
3.5.1-021	Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses; reinforcing steel	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. Cracking; loss of bond; and loss of material (spalling, scaling) of Containment concrete elements (accessible areas) is managed by the ASME Section XI, Subsection IWL (B2.1.30) program.
3.5.1-023	Concrete (inaccessible areas): basemat; reinforcing steel, dome; wall	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S2, ASME Section XI, Subsection IWL, and/or AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191. Cracking; loss of bond; and loss of material (spalling, scaling) of Containment concrete elements (inaccessible areas) is managed by the ASME Section XI, Subsection IWL (B2.1.30) program and the Structures Monitoring (B2.1.34) program.
3.5.1-024	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, concrete (accessible areas): dome; wall; basemat	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	AMP XI.S2, ASME Section XI, Subsection IWL, and/or AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191. Increase in porosity and permeability; cracking; loss of material (spalling, scaling) of Containment concrete elements (inaccessible areas) is managed by the ASME Section XI, Subsection IWL (B2.1.30) program and the Structures Monitoring (B2.1.34) program.

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

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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, Subsection IWE	No	Consistent with NUREG-2191.
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, Subsection 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. In addition to Containment Structure, components in Auxiliary Systems (fuel handling) are aligned to this row. See further evaluation in Section 3.5.2.2.1.5.
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.
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.
3.5.1-030	Pressure-retaining bolting	Loss of preload due to self-loosening	AMP XI.S1, ASME Section XI, Subsection IWE, and AMP XI.S4, 10 CFR Part 50, Appendix J	No	Consistent with NUREG-2191.
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, Subsection IWE	No	Consistent with NUREG-2191.
3.5.1-032	Prestressing system: tendons; anchorage components	Loss of material due to corrosion	AMP XI.S2, ASME Section XI, Subsection IWL	No	Not applicable. NAPS does not have prestressed Containment structures. The associated NUREG-2191 aging items are not used.

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

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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.
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.
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, Subsection IWE, and AMP XI.S4, 10 CFR Part 50, Appendix J	Yes (SRP-SLR Section 3.5.2.2.1.3.1)	Consistent with NUREG-2191. See further evaluation in Section 3.5.2.2.1.3.1.
3.5.1-036	Steel elements: drywell head; downcomers	Loss of material due to mechanical wear, including fretting	AMP XI.S1, ASME Section XI, Subsection IWE	No	Not applicable - BWR only.
3.5.1-037	Steel elements: suppression chamber (torus) liner (interior surface)	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.S1, ASME Section XI, Subsection IWE, and AMP XI.S4, 10 CFR Part 50, Appendix J	No	Not applicable - BWR only.
3.5.1-038	Steel elements: suppression chamber shell (interior surface)	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)	Not applicable - BWR only.

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

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-039	Steel elements: vent line 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)	Not applicable - BWR only.
3.5.1-040	Unbraced downcomers, steel elements: vent header; downcomers	Cracking due to cyclic loading (CLB fatigue analysis does not exist)	AMP XI.S1, ASME Section XI, Subsection IWE	Yes (SRP-SLR Section 3.5.2.2.1.5)	Not applicable - BWR only.
3.5.1-041	Steel elements: drywell support skirt, steel elements (inaccessible areas): support skirt	None	None	No	Not applicable - BWR only.
3.5.1-042	Groups 1-3, 5, 7- 9: concrete (inaccessible areas): foundation	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Plant-specific aging management program, or AMP XI.S6, Structures Monitoring, enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.1.1)	Not applicable. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.5.2.2.2.1.1.
3.5.1-043	All Groups except Group 6: concrete (inaccessible areas): all	Cracking due to expansion from reaction with aggregates	Plant-specific aging management program, or AMP XI.S6, Structures Monitoring, enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.1.2)	Consistent with NUREG-2191. The aging management program used to manage cracking of concrete elements (inaccessible areas) for all groups, except Group 6, is the Structures Monitoring (B2.1.34) program. See further evaluation in Section 3.5.2.2.2.1.2.
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)	Consistent with NUREG-2191. See further evaluation in Section 3.5.2.2.2.1.3.

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

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-046	Groups 1-3, 5-9: 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 3.5.2.2.2.1.3)	Consistent with NUREG-2191 for differential settlement, not applicable for erosion of porous concrete other than Containment. See further evaluation in Section 3.5.2.2.2.1.3.
3.5.1-047	Groups 1-5, 7-9: concrete (inaccessible areas): exterior above- and below-grade; foundation	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Plant-specific aging management program, or AMP XI.S6, Structures Monitoring, enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.1.4)	Not applicable. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.5.2.2.2.1.4.
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 aging management program, or AMP XI.S6, Structures Monitoring, enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.2)	Not applicable. Temperature thresholds for reduction of strength and modulus of elasticity are not exceeded. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.5.2.2.2.2.
3.5.1-049	Groups 6 - concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Plant-specific aging management program, or AMP XI.S6, Structures Monitoring, enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.3.1)	Not applicable. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.5.2.2.2.3.1.
3.5.1-050	Groups 6: concrete (inaccessible areas): all	Cracking due to expansion from reaction with aggregates	Plant-specific aging management program, or AMP XI.S6, Structures Monitoring, enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.3.2)	Consistent with NUREG-2191. The aging management program used to manage cracking of Group 6 concrete elements (inaccessible areas) is the Structures Monitoring (B2.1.34) program. See further evaluation in Section 3.5.2.2.2.3.2.

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

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-051	Groups 6: concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Plant-specific aging management program, or AMP XI.S6, Structures Monitoring, enhanced as necessary	Yes (SRP-SLR Section 3.5.2.2.2.3.3)	Not applicable. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.5.2.2.2.3.3.
3.5.1-052	Groups 7, 8 - steel components: tank liner	Cracking due to SCC; Loss of material due to pitting and crevice corrosion	Plant-specific aging management program	Yes (SRP-SLR Section 3.5.2.2.2.4)	Consistent with NUREG-2191. The plant specific aging management program used to manage cracking and loss of material is the Structures Monitoring (B2.1.34) program. See further evaluation 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. There are no TLAAs associated with support members, anchor bolts, and welds for component supports. The associated NUREG-2191 aging items are not used. See further evaluation 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.
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.

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

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-056	Concrete: exterior above- and below- grade; foundation; interior slab	Loss of material due to abrasion; cavitation	AMP XI.S7, Inspection of Water-Control Structures Associated with Nuclear Power Plants or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. Loss of material of concrete elements exposed to water-flowing is managed by the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35) program.
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, however, a different aging management program is credited for some components. Supports for non-ASME Code piping systems and components are aligned to this row. For supports for non-ASME Code piping systems and components, the aging management program used to manage the loss of mechanical function is the Structures Monitoring (B2.1.34) program.
3.5.1-058	Earthen water-control structures: dams; embankments; reservoirs; channels; canals and ponds	Loss of material; loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	AMP XI.S7, Inspection of Water-Control Structures Associated with Nuclear Power Plants or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. Loss of material and loss of form of earthen dike and embankment are managed by the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35) program.
3.5.1-059	Group 6: concrete (accessible areas): all	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S7, Inspection of Water-Control Structures Associated with Nuclear Power Plants or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. Cracking; loss of bond; and loss of material (spalling, scaling) of Group 6 concrete elements (accessible areas) are managed by the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35) program.

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

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-060	Group 6: concrete (accessible areas): exterior above- and below-grade; foundation	Loss of material (spalling, scaling) and cracking due to freeze-thaw	AMP XI.S7, Inspection of Water-Control Structures Associated with Nuclear Power Plants or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. Loss of material (spalling, scaling) and cracking of Group 6 concrete elements (accessible areas) are managed by the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35) program.
3.5.1-061	Group 6: concrete (accessible areas): exterior above- and below-grade; foundation; interior slab	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	AMP XI.S7, Inspection of Water-Control Structures Associated with Nuclear Power Plants or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. Increase in porosity and permeability; and loss of strength of Group 6 concrete elements (accessible areas) are managed by the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35) program.
3.5.1-062	Group 6: Wooden Piles; sheeting	Loss of material; change in material properties due to weathering, chemical degradation, and insect infestation repeated wetting and drying, fungal decay	AMP XI.S7, Inspection of Water-Control Structures Associated with Nuclear Power Plants or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Not applicable. NAPS has no in-scope Group 6: Wooden Piles; sheeting in the Containments, Structures, and Component Supports. The associated NUREG-2191 aging items are not used.
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.
3.5.1-064	Groups 1-3, 5, 7-9: concrete (accessible areas): exterior above- and below-grade; foundation	Loss of material (spalling, scaling) and cracking due to freeze-thaw	AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191.

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

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-065	Groups 1-3, 5, 7-9: concrete (inaccessible areas): below-grade exterior; foundation, Groups 1-3, 5, 7-9: concrete (accessible areas): below-grade exterior; foundation, Groups 6: concrete (inaccessible areas): all	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191.
3.5.1-066	Groups 1-5, 7, 9: concrete (accessible areas): interior and above-grade exterior	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.
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.
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.
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.

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

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-071	Masonry walls: all	Loss of material (spalling, scaling) and cracking due to freeze-thaw	AMP XI.S5, Masonry Walls	No	Consistent with NUREG-2191.
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.
3.5.1-073	Service Level I coatings	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage	AMP XI.S8, Protective Coating Monitoring and Maintenance	No	Consistent with NUREG-2191.
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	Consistent with NUREG-2191.
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.
3.5.1-076	Sliding surfaces: radial beam seats in BWR drywell	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	AMP XI.S6, Structures Monitoring	No	Not applicable - BWR only.

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

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
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. In addition to Containments, Structures, and Component Supports, the neutron shield tank in the Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant system), is also aligned to this row.
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. Monitoring of the spent fuel pool water level and leakage from the leak chase channels is performed by the Structures Monitoring (B2.1.34) program.
3.5.1-079	Steel components: piles	Loss of material due to corrosion	AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191.
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.
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.
3.5.1-082	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S6, Structures Monitoring	No	Not applicable. Galvanized steel structural bolting is evaluated using NUREG-2191 rows for steel structural bolting. Refer to Item Number 3.5.1-080. The associated NUREG-2191 aging items are not used.

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

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-083	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S7, Inspection of Water-Control Structures Associated with Nuclear Power Plants or the FERC/US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191 for Water-Control structures. For Water-Control structures, loss of material will be managed by the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35) program. In addition, bolting associated with component supports are aligned to this row, for which different aging management programs are assigned. For component supports, loss of material will be managed by the Structures Monitoring (B2.1.34) program and ASME Section XI, Subsection IWF (B2.1.30) program.
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 applicable. NAPS has no in-scope stainless steel structural bolting exposed to treated water in the Containments, Structures, and Component Supports. The associated NUREG-2191 aging items are not used.
3.5.1-086	Structural bolting	Loss of material due to pitting, crevice corrosion	AMP XI.S3, ASME Section XI, Subsection IWF	No	Not applicable. Galvanized steel structural bolting is evaluated using NUREG-2191 rows for steel structural bolting. Refer to Item Number 3.5.1-081. The associated NUREG-2191 aging items are not used.
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.
3.5.1-088	Structural bolting	Loss of preload due to self-loosening	AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191 with a different program assigned for bolting associated with the materials handling system and Containment. In addition to Structures and Component Supports, stainless steel components in Auxiliary Systems (materials handling) and Containment are aligned to this row. Loss of preload of stainless steel bolting in Auxiliary Systems (materials handling) will be managed by the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B2.1.13) program. Loss of preload of Containment stainless steel bolting will be managed by the ASME Section XI, Subsection IWE (B2.1.29) and 10 CFR Part 50, Appendix J (B2.1.32) programs.

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

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-089	Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to boric acid corrosion	AMP XI.M10, Boric Acid Corrosion	No	Consistent with NUREG-2191.
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 applicable. NAPS has no in-scope support members; welds; bolted connections; support anchorage to building structure exposed to treated water in the Containments, Structures, and Component Supports. The associated NUREG-2191 aging items are not used.
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.
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.
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	Not applicable. Galvanized steel components are evaluated using NUREG-2191 rows for steel. Refer to Item Number 3.5.1-092. The associated NUREG-2191 aging items are not used.
3.5.1-094	Vibration isolation elements	Reduction or loss of isolation function due to radiation hardening, temperature, humidity, sustained vibratory loading	AMP XI.S3, ASME Section XI, Subsection IWF, and/or AMP XI.S6, Structures Monitoring	No	Consistent with NUREG-2191. Reduction or loss of isolation function of vibration isolation elements is managed by the Structures Monitoring (B2.1.34) program. There are no non-metallic vibration isolation elements within the scope of the IWF program.

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

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-095	Galvanized steel support members; welds; bolted connections; support anchorage to building structure	None	None	No	Not applicable. Galvanized steel components are evaluated using NUREG-2191 rows for steel. Refer to Item Number 3.5.1-092. The associated NUREG-2191 aging items are not used.
3.5.1-096	Groups 6: concrete (accessible areas): all	Cracking due to expansion from reaction with aggregates	AMP XI.S7, Inspection of Water-Control Structures Associated with Nuclear Power Plants	No	Consistent with NUREG-2191.
3.5.1-097	Group 4: Concrete (reactor cavity area proximate to the reactor vessel): reactor (primary/biological) shield wall; sacrificial shield wall; reactor vessel support/pedestal structure	Reduction of strength; loss of mechanical properties due to irradiation (i.e., radiation interactions with material and radiation-induced heating)	Plant-specific aging management program or plant-specific enhancements to selected AMPs	Yes (SRP-SLR Section 3.5.2.2.2.6)	Not applicable. See further evaluation in Section 3.5.2.2.2.6.
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.
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)	Consistent with NUREG-2191. There are no aluminum support components that are within the scope of the ASME Section XI, Subsection IWF (B2.1.31) program. Loss of material and cracking of stainless steel support members; welds; bolted connections; support anchorage to building structure are managed by the ASME Section XI, Subsection IWF (B2.1.31) program. See further evaluation in Section 3.5.2.2.2.4.

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

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.5.1-100	Aluminum, stainless steel support members; welds; bolted connections; support anchorage to building structure	Loss of material due to pitting and crevice corrosion; cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.S6, Structures Monitoring, or AMP XI.M36, External Surfaces Monitoring of Mechanical Components	Yes (SRP-SLR Section 3.5.2.2.2.4)	Consistent with NUREG-2191. Loss of material and cracking of aluminum, stainless steel support members; welds; bolted connections; support anchorage to building structure are managed by the Structures Monitoring (B2.1.34) program. In addition to Structures and Component Supports, stainless steel components in Auxiliary Systems (materials handling) are aligned to this row and are managed by the Structures Monitoring (B2.1.34) program. See further evaluation in Section 3.5.2.2.2.4.

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Results Tables: Containment, Structures and Component Supports AMR Results

Table 3.5.2-1 Containment Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Blind flange (electrical penetrations)	PB	Stainless steel	(E) Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-38	3.5.1-010	C
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-38	3.5.1-010	C
				Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	A
Bolting	PB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-148	3.5.1-031	A
					Structures Monitoring (B2.1.34)	III.A4.TP-248	3.5.1-080	A
				Loss of preload	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-150	3.5.1-030	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-150	3.5.1-030	A
					Structures Monitoring (B2.1.34)	III.A4.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-148	3.5.1-031	A
					Structures Monitoring (B2.1.34)	III.A4.TP-248	3.5.1-080	A
				Loss of preload	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-150	3.5.1-030	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-150	3.5.1-030	A
					Structures Monitoring (B2.1.34)	III.A4.TP-261	3.5.1-088	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-38	3.5.1-010	C
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-38	3.5.1-010	C
				Loss of preload	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.TP-261	3.5.1-088	E, 7
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.TP-261	3.5.1-088	E, 7
Concrete blocks	EN	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A1.T-12	3.5.1-070	A

Table 3.5.2-1 Containment Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB;JIS;MB;PB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A4.TP-204	3.5.1-043	A, 1
						III.A4.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A4.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A4.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-67	3.5.1-012	A, 1
						II.A1.CP-33	3.5.1-019	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-68	3.5.1-021	A, 1
						II.A1.CP-97	3.5.1-023	A, 1
					Structures Monitoring (B2.1.34)	II.A1.CP-97	3.5.1-023	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-87	3.5.1-016	A, 1
						II.A1.CP-100	3.5.1-024	A, 1
					Structures Monitoring (B2.1.34)	II.A1.CP-100	3.5.1-024	A, 1
				Loss of material (spalling, scaling) and cracking	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-31	3.5.1-018	A, 1

Table 3.5.2-1 Containment Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB;JIS;MB;PB;SS	Concrete	(E) Groundwater	Cracking	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-67	3.5.1-012	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-100	3.5.1-024	A, 1
					Structures Monitoring (B2.1.34)	II.A1.CP-100	3.5.1-024	A, 1
			(E) Soil	Cracking	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-67	3.5.1-012	A, 1
				Cracking and distortion	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-101	3.5.1-001	A, 1
					Structures Monitoring (B2.1.34)	II.A1.CP-101	3.5.1-001	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-97	3.5.1-023	A, 1
					Structures Monitoring (B2.1.34)	II.A1.CP-97	3.5.1-023	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-100	3.5.1-024	A, 1
					Structures Monitoring (B2.1.34)	II.A1.CP-100	3.5.1-024	A, 1
			(E) Water – flowing	Cracking; loss of bond; and loss of material (spalling, scaling)	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-97	3.5.1-023	A, 1
					Structures Monitoring (B2.1.34)	II.A1.CP-97	3.5.1-023	A, 1
				Increase in porosity and permeability; loss of strength	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-32	3.5.1-020	A, 1
					Structures Monitoring (B2.1.34)	III.A1.TP-24	3.5.1-063	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	II.A1.C-07	3.5.1-002	A, 1
		Reinforced concrete	(E) Air	Cracking; loss of material	ASME Section XI, Subsection IWL (B2.1.30)	VII.G.A-90	3.3.1-060	E, 1, 3
					Fire Protection (B2.1.15)	VII.G.A-90	3.3.1-060	A, 1

Table 3.5.2-1 Containment Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Containment liner	PB;SS	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-40	3.5.1-026	A, 6
		Steel	(E) Air – indoor uncontrolled	Cumulative fatigue damage (Only if CLB fatigue analysis exists)	TLAA	II.A3.C-13	3.5.1-009	A, 6
				Loss of material	10 CFR Part 50, Appendix J (B2.1.32)	II.A1.CP-98	3.5.1-005	A, 6
					ASME Section XI, Subsection IWE (B2.1.29)	II.A1.CP-98	3.5.1-005	A, 6
					10 CFR Part 50, Appendix J (B2.1.32)	II.A1.CP-35	3.5.1-035	A, 6
					ASME Section XI, Subsection IWE (B2.1.29)	II.A1.CP-35	3.5.1-035	A, 6
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B1.1.T-25	3.5.1-089	C, 6
Containment sump liner	PB;SS	Stainless steel	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B2.T-37b	3.5.1-100	C
			(E) Water – standing	Cracking; loss of material	Structures Monitoring (B2.1.34)	III.A7.T-23	3.5.1-052	E, 2
Equipment hatch, personnel air lock, emergency escape locks, and accessories (hinges, pins, closure mechanisms)	EN;MB;PB;SS	Steel	(E) Air – indoor uncontrolled	Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	A
				Loss of leak tightness	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-39	3.5.1-029	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-39	3.5.1-029	A
				Loss of material	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.C-16	3.5.1-028	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.C-16	3.5.1-028	A
			(E) Air – outdoor	Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	A
				Loss of leak tightness	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-39	3.5.1-029	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-39	3.5.1-029	A
				Loss of material	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.C-16	3.5.1-028	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.C-16	3.5.1-028	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	C

Table 3.5.2-1 Containment Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Fuel transfer tube enclosure protection shield	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A1.TP-302	3.5.1-077	A
Penetrations (electrical)	PB;SS	Steel	(E) Air – indoor uncontrolled	Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	A
				Loss of material	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-36	3.5.1-035	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-36	3.5.1-035	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	C
Penetrations (mechanical)	EN;PB;SS	Dissimilar metal welds	(E) Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-38	3.5.1-010	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-38	3.5.1-010	A
				Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	A
				Loss of material	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-36	3.5.1-035	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-36	3.5.1-035	A
		Stainless steel	(E) Air – indoor uncontrolled	Cracking	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-38	3.5.1-010	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-38	3.5.1-010	A
				Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	A
		Steel	(E) Air – indoor uncontrolled	Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	A
				Loss of material	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-36	3.5.1-035	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-36	3.5.1-035	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	C
Porous concrete	SS	Porous concrete	(E) Water – flowing	Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	II.A1.C-07	3.5.1-002	A
Reactor cavity liner	PB;SS	Stainless steel	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B2.T-37b	3.5.1-100	C
			(E) Treated borated water	Cracking; loss of material	Structures Monitoring (B2.1.34)	III.A5.T-14	3.5.1-078	A
					Water Chemistry (B2.1.2)	III.A5.T-14	3.5.1-078	A

Table 3.5.2-1 Containment Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Seals and gaskets	PB;SS	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-41	3.5.1-033	A, 5
Service Level I coatings	MCI	Coatings	(E) Air – indoor uncontrolled	Loss of coating or lining integrity	Protective Coating Monitoring and Maintenance (B2.1.36)	II.A3.CP-152	3.5.1-034	A
						III.A4.TP-301	3.5.1-073	A
Steel elements	EN;MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A4.TP-302	3.5.1-077	A, 4
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A1.TP-302	3.5.1-077	A, 4
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	C, 4
Waterproofing membrane	EN;FLB	Elastomer, rubber and other similar materials	(E) Groundwater	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Soil	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A

Table 3.5.2-1 Plant-Specific Notes:

1. Concrete elements include beams, columns, walls, slabs, curbs, foundations, pads, dikes, jet impingement barriers, missile barriers, and the exterior concrete for the Containment.
2. The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the Structures Monitoring (B2.1.34) program.
3. The ASME Section XI, Subsection IWL (B2.1.30) program is used instead of Structures Monitoring (B2.1.34) program to manage the applicable aging effect(s) for this component type, material, and environment combination.
4. Steel elements include beams, columns, baseplates, bracing, stairs, platforms, grating, decking, ladders, doors, missile barriers, and embedded steel.
5. Seals and gaskets include O-rings for personnel air locks, equipment hatches, emergency escape locks, penetration flanges, fuel transfer tube blind flange, and other elastomer materials that are part of the Containment pressure boundary.
6. Containment liner includes liner plates, basemat liner leak chase channel test connections, liner anchors, and integral attachments.
7. The ASME Section XI, Subsection IWE (B2.1.29) and 10 CFR Part 50, Appendix J (B2.1.32) programs are used instead of Structures Monitoring (B2.1.34) program to manage the applicable aging effect(s) for this component type, material, and environment combination.

Table 3.5.2-2 Structures and Component Supports - Administration Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-2 Structures and Component Supports - Administration Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-31	3.5.1-046	A, 1
Doors	EN;FB	Steel	(E) Air	Loss of material	Fire Protection (B2.1.15)	VII.G.A-21	3.3.1-059	A
			(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A
Masonry block walls	EN;FB;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
		Masonry walls	(E) Air	Cracking; loss of material	Fire Protection (B2.1.15)	VII.G.A-626	3.3.1-179	A
					Masonry Walls (B2.1.33)	VII.G.A-626	3.3.1-179	A
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-2 Plant-Specific Notes:

1. Concrete elements include walls, slabs, and foundations.
2. Steel elements include beams, columns, siding, baseplates, decking, and embedded steel.

Table 3.5.2-3 Structures and Component Supports - Auxiliary Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Aluminum elements	EN	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B2.T-37b	3.5.1-100	C, 3
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	A
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-3 Structures and Component Supports - Auxiliary Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-31	3.5.1-046	A, 1
		Reinforced concrete	(E) Air	Cracking; loss of material	Fire Protection (B2.1.15)	VII.G.A-90	3.3.1-060	A, 1
					Structures Monitoring (B2.1.34)	VII.G.A-90	3.3.1-060	A, 1
Doors	EN;FB;MB	Steel	(E) Air	Loss of material	Fire Protection (B2.1.15)	VII.G.A-21	3.3.1-059	A
			(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	C
Masonry block walls	EN;FB;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
		Masonry walls	(E) Air	Cracking; loss of material	Fire Protection (B2.1.15)	VII.G.A-626	3.3.1-179	A
					Masonry Walls (B2.1.33)	VII.G.A-626	3.3.1-179	A
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A

Table 3.5.2-3 Structures and Component Supports - Auxiliary Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Steel elements	EN;FB;FLB; MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	C, 2

Table 3.5.2-3 Plant-Specific Notes:

1. Concrete elements include beams, columns, foundation, walls, hatches, missile barriers, pads, and slabs.
2. Steel elements include beams, columns, ladders, stairs, baseplates, decking, grating, siding, dikes, missile shields, and embedded steel.
3. Aluminum elements include louvers and screens.

Table 3.5.2-4 Structures and Component Supports - Auxiliary Feedwater Pump House - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;FB;MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-4 Structures and Component Supports - Auxiliary Feedwater Pump House - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;MB;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
		Reinforced concrete	(E) Air	Cracking; loss of material	Fire Protection (B2.1.15)	VII.G.A-90	3.3.1-060	A, 1
					Structures Monitoring (B2.1.34)	VII.G.A-90	3.3.1-060	A, 1
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-4 Plant-Specific Notes:

1. Concrete elements include foundation, internal structural members, walls, pads, hatches, and roof slabs.
2. Steel elements include doors, beams, baseplates, grating, screens, and embedded steel.

Table 3.5.2-5 Structures and Component Supports - Auxiliary Feedwater Tunnel - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Stainless steel	(E) Air – indoor uncontrolled	Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B5.T-37b	3.5.1-100	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-5 Structures and Component Supports - Auxiliary Feedwater Tunnel - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;MB;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-31	3.5.1-046	A, 1
Stainless steel elements	EN;MB;SS	Stainless steel	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B5.T-37b	3.5.1-100	C, 2
Steel elements	EN;MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3

Table 3.5.2-5 Plant-Specific Notes:

1. Concrete elements include walls, slabs, and foundations.
2. Stainless steel elements include missile barriers.
3. Steel elements include manhole covers, ladders, baseplates, and embedded steel.

Table 3.5.2-6 Structures and Component Supports - Boron Recovery Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Aluminum elements	EN	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B2.T-37b	3.5.1-100	C, 3
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	A
Concrete elements	EN;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-6 Structures and Component Supports - Boron Recovery Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	C, 2

Table 3.5.2-6 Plant-Specific Notes:

1. Concrete elements include walls, slabs, foundation, pads, and dikes.
2. Steel elements include beams, columns, baseplates, decking, doors, siding, and embedded steel.
3. Aluminum elements include louvers and screens.

Table 3.5.2-7 Structures and Component Supports - Casing Cooling Pump House - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Aluminum elements	EN	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B2.T-37b	3.5.1-100	C, 3
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-7 Structures and Component Supports - Casing Cooling Pump House - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-7 Plant-Specific Notes:

1. Concrete elements include foundation, walls, pads, and slabs.
2. Steel elements include beams, columns, doors, baseplates, grating, and embedded steel.
3. Aluminum elements include louvers and screens.

Table 3.5.2-8 Structures and Component Supports - Circulating Water Intake Tunnel Header - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-34	3.5.1-096	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 1
					Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 1
			(E) Groundwater	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-107	3.5.1-067	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A6.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-107	3.5.1-067	A, 1

Table 3.5.2-8 Structures and Component Supports - Circulating Water Intake Tunnel Header - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	SS	Concrete	(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-34	3.5.1-096	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 1
				Increase in porosity and permeability; loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 1
				Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-20	3.5.1-056	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	III.A6.TP-31	3.5.1-046	A, 1
Steel piles	SS	Steel	(E) Groundwater	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-219	3.5.1-079	A
			(E) Soil	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-219	3.5.1-079	A

Table 3.5.2-8 Plant-Specific Notes:

1. Concrete elements include beams, columns, walls, slabs, and foundations.

Table 3.5.2-9 Structures and Component Supports - Containment Mat Subsurface Pump Access Shaft - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-9 Structures and Component Supports - Containment Mat Subsurface Pump Access Shaft - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1

Table 3.5.2-9 Plant-Specific Notes:

1. Concrete elements include shaft walls and hatch.

Table 3.5.2-10 Structures and Component Supports - Decontamination Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Aluminum elements	EN	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B2.T-37b	3.5.1-100	C, 3
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-10 Structures and Component Supports - Decontamination Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-31	3.5.1-046	A, 1
Masonry block walls	EN	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
			(E) Air – outdoor	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
				Loss of material (spalling, scaling) and cracking	Masonry Walls (B2.1.33)	III.A3.TP-34	3.5.1-071	A
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-10 Plant-Specific Notes:

1. Concrete elements include walls, slabs, foundation, pads, and dikes.
2. Steel elements include beams, columns, baseplates, decking, doors, siding, and embedded steel.
3. Aluminum elements include louvers and screens.

Table 3.5.2-11 Structures and Component Supports - Dikes, Firewalls, and Equipment Foundations - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	FB;FLB;SS	Concrete	(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
Steel elements	SS	Steel	(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-11 Plant-Specific Notes:

1. Concrete elements include dikes, foundations, walls, and pads.
2. Steel elements include beams, columns, baseplates, and embedded steel.

Table 3.5.2-12 Structures and Component Supports - Discharge Tunnel & Seal Pit - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	BWI;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-34	3.5.1-096	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 1
					Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-34	3.5.1-096	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 1
					Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 1
				Loss of material (spalling, scaling) and cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-36	3.5.1-060	A, 1
			(E) Groundwater	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-107	3.5.1-067	A, 1

Table 3.5.2-12 Structures and Component Supports - Discharge Tunnel & Seal Pit - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	BWI;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A6.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-107	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-34	3.5.1-096	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 1
				Increase in porosity and permeability; loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 1
				Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-20	3.5.1-056	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	III.A6.TP-31	3.5.1-046	A, 1

Table 3.5.2-12 Plant-Specific Notes:

1. Concrete elements include beams, walls, slabs, and foundations.

Table 3.5.2-13 Structures and Component Supports - Domestic Water Treatment Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-13 Structures and Component Supports - Domestic Water Treatment Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-31	3.5.1-046	A, 1
Masonry block walls	EN;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
			(E) Air – outdoor	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
				Loss of material (spalling, scaling) and cracking	Masonry Walls (B2.1.33)	III.A3.TP-34	3.5.1-071	A
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-13 Plant-Specific Notes:

1. Concrete elements include mat foundation.
2. Steel elements include beams, columns, baseplates, doors; decking, and embedded steel.

Table 3.5.2-14 Structures and Component Supports - Duck Banks - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1

Table 3.5.2-14 Plant-Specific Notes:

1. Concrete elements include duct banks and cable trenches.

Table 3.5.2-15 Structures and Component Supports - Flood Protection Dike - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Stainless steel	(E) Raw water	Loss of preload	Structures Monitoring (B2.1.34)	III.B5.TP-261	3.5.1-088	A
Concrete elements	EN;SS	Concrete	(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 6
						III.A3.TP-25	3.5.1-054	A, 6
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 6
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 6
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 6
						III.A3.TP-27	3.5.1-065	A, 6
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 6
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 6
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 6
						III.A3.TP-27	3.5.1-065	A, 6
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 6
			(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 6
Earthen dike and embankment	FLB;SS	Earthfill (rip-rap, stone, soil)	(E) Air – outdoor	Loss of material; loss of form	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-22	3.5.1-058	A
			(E) Water – standing	Loss of material; loss of form	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-22	3.5.1-058	A

Table 3.5.2-15 Structures and Component Supports - Flood Protection Dike - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	FLB	Any material with an internal coating/lining	(I) Raw water	Loss of coating or lining integrity; loss of material or cracking (for cementitious coatings/linings)	Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)	VII.G.A-416	3.3.1-138	B
		Steel	(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A
			(E) Raw water	Loss of material	Structures Monitoring (B2.1.34)	VII.G.A-412	3.3.1-136	E, 3
			(E) Soil	Loss of material	Buried and Underground Piping and Tanks (B2.1.27)	VII.I.AP-198	3.3.1-109	A
Steel elements	SS	Steel	(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 7
Valve body	FLB	Gray cast iron	(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	VII.I.A-77	3.3.1-078	E, 1, 5
			(I) Air – outdoor	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.I.A-77	3.3.1-078	E, 1, 2
			(E) Raw water	Loss of material	Selective Leaching (B2.1.21)	VII.C3.A-51	3.3.1-072	A, 1
					Structures Monitoring (B2.1.34)	VII.G.A-412	3.3.1-136	E, 1, 3
			(I) Raw water	Loss of material	Selective Leaching (B2.1.21)	VII.C3.A-51	3.3.1-072	A, 1
					Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.G.A-412	3.3.1-136	E, 1, 4

Table 3.5.2-15 Plant-Specific Notes:

1. Valve body includes frame for sluice gate valve.

2. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program instead of the External Surfaces Monitoring of Mechanical Components (B2.1.23) program will manage the aging effects applicable to this component type, material, and environment combination for piping and valves associated with the flood wall west of the Turbine Building.

3. The Structures Monitoring (B2.1.34) program instead of the Fire Water System (B2.1.16) program will manage the aging effects applicable to this component type, material, and environment combination for piping and valves associated with the flood wall west of the Turbine Building.

4. The Inspection of Internal Surfaces in Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program instead of the Fire Water System (B2.1.16) program will manage the aging effects applicable to this component type, material, and environment combination for piping and valves associated with the flood wall west of the Turbine Building.

5. The Structures Monitoring (B2.1.34) program instead of the External Surfaces Monitoring of Mechanical Components (B2.1.23) program will manage the aging effects applicable to this component type, material, and environment combination for piping and valves associated with the flood wall west of the Turbine Building.

6. Concrete elements include catch basin.

7. Steel elements include metal grate.

Table 3.5.2-16 Structures and Component Supports - Fuel Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Stainless steel	(E) Air – indoor uncontrolled	Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B5.T-37b	3.5.1-100	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A5.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A5.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A5.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A5.TP-261	3.5.1-088	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	A
Concrete elements	EN;FLB;MB; SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A5.TP-204	3.5.1-043	A, 1
						III.A5.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A5.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A5.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A5.TP-204	3.5.1-043	A, 1
						III.A5.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A5.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A5.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A5.TP-23	3.5.1-064	A, 1

Table 3.5.2-16 Structures and Component Supports - Fuel Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FLB;MB; SS	Concrete	(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A5.TP-212	3.5.1-065	A, 1
						III.A5.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A5.TP-29	3.5.1-067	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A5.TP-204	3.5.1-043	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A5.TP-212	3.5.1-065	A, 1
						III.A5.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A5.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A5.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A5.TP-24	3.5.1-063	A, 1
Masonry block walls	EN;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A5.T-12	3.5.1-070	A
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Spent fuel pool liner plates	EN;PB;SS	Stainless steel	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B5.T-37b	3.5.1-100	A
			(E) Treated borated water	Cracking; loss of material	Structures Monitoring (B2.1.34)	III.A5.T-14	3.5.1-078	A
					Water Chemistry (B2.1.2)	III.A5.T-14	3.5.1-078	A
				Cumulative fatigue damage	TLAA	None	None	H, 4
Stainless steel elements	EN;PB;SS	Stainless steel	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B5.T-37b	3.5.1-100	A, 3
			(E) Treated borated water	Cracking; loss of material	Structures Monitoring (B2.1.34)	III.A5.T-14	3.5.1-078	C, 3
					Water Chemistry (B2.1.2)	III.A5.T-14	3.5.1-078	C, 3

Table 3.5.2-16 Structures and Component Supports - Fuel Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A5.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A5.TP-302	3.5.1-077	A, 2
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	C, 2

Table 3.5.2-16 Plant-Specific Notes:

1. Concrete elements include beams, columns, foundation, walls, pads, and slabs.
2. Steel elements include beams, columns, doors, ladders, stairs, baseplates, decking, grating, siding, and embedded steel.
3. Stainless steel elements include transfer canal gates, spent fuel storage racks, and new fuel storage racks.
4. The evaluation of the spent fuel pool liner plates fatigue is addressed in Section 4.7.4 Spent Fuel Pool Liner Fatigue Analysis.

Table 3.5.2-17 Structures and Component Supports - Fuel Oil Pump House - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;FB;MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-17 Structures and Component Supports - Fuel Oil Pump House - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;MB;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
		Reinforced concrete	(E) Air	Cracking; loss of material	Fire Protection (B2.1.15)	VII.G.A-90	3.3.1-060	A, 1
					Structures Monitoring (B2.1.34)	VII.G.A-90	3.3.1-060	A, 1
Steel elements	EN;MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-17 Plant-Specific Notes:

1. Concrete elements include foundation, internal structural members, slabs, walls, pads, and roof slabs.
2. Steel elements include doors, ladders, baseplates, and embedded steel.

Table 3.5.2-18 Structures and Component Supports - Intake Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Aluminum elements	EN	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B2.T-37b	3.5.1-100	C, 3
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A6.TP-248	3.5.1-080	A
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A6.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A6.TP-248	3.5.1-080	A
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A6.TP-261	3.5.1-088	A
			(E) Water – flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	A
			(E) Water – standing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	A
Concrete elements	BWI;EN;FB; MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-34	3.5.1-096	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 1
					Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 1

Table 3.5.2-18 Structures and Component Supports - Intake Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	BWI;EN;FB; MB;SS	Concrete	(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-34	3.5.1-096	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 1
					Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 1
				Loss of material (spalling, scaling) and cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-36	3.5.1-060	A, 1
			(E) Groundwater	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-107	3.5.1-067	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A6.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-107	3.5.1-067	A, 1

Table 3.5.2-18 Structures and Component Supports - Intake Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	BWI;EN;FB; MB;SS	Concrete	(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-34	3.5.1-096	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 1
				Increase in porosity and permeability; loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 1
				Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-20	3.5.1-056	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	III.A6.TP-31	3.5.1-046	A, 1
Masonry block walls	EN;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A6.T-12	3.5.1-070	A
			(E) Air – outdoor	Cracking	Masonry Walls (B2.1.33)	III.A6.T-12	3.5.1-070	A
				Loss of material (spalling, scaling) and cracking	Masonry Walls (B2.1.33)	III.A6.TP-34	3.5.1-071	A
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;FLB;FLT; MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	C, 2
			(E) Air – outdoor	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	C, 2
			(E) Water – flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	C, 2
			(E) Water – standing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	C, 2

Table 3.5.2-18 Plant-Specific Notes:

1. Concrete elements include beams, columns, walls, slabs, curbs, pads, and foundations.

2. Steel elements include beams, columns, baseplates, stairs, platforms, grating, decking, ladders, embedded steel, doors, louvers, screens, trash racks, and missile shields.

3. Aluminum elements include roof access covers, louvers, and screens.

Table 3.5.2-19 Structures and Component Supports - Main Steam Valve House - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-19 Structures and Component Supports - Main Steam Valve House - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-31	3.5.1-046	A, 1
		Reinforced concrete	(E) Air	Cracking; loss of material	Fire Protection (B2.1.15)	VII.G.A-90	3.3.1-060	A, 1
					Structures Monitoring (B2.1.34)	VII.G.A-90	3.3.1-060	A, 1
Masonry block walls	EN;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-19 Plant-Specific Notes:

1. Concrete elements include beams, columns, foundation, walls, pads, hatches, and roof slabs.
2. Steel elements include beams, columns, doors, stairs, baseplates, decking, grating, and embedded steel.

Table 3.5.2-20 Structures and Component Supports - Maintenance Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-20 Structures and Component Supports - Maintenance Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
Masonry block walls	EN;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-20 Plant-Specific Notes:

1. Concrete elements include walls, slabs, and foundation.
2. Steel elements include beams, columns, baseplates, grating, decking, doors, and embedded steel.

Table 3.5.2-21 Structures and Component Supports - Manholes - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-21 Structures and Component Supports - Manholes - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;MB;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
Steel elements	EN;MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-21 Plant-Specific Notes:

1. Concrete elements include manhole structures.
2. Steel elements include manhole covers and ladders.

Table 3.5.2-22 Structures and Component Supports - New Fuel Receiving Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Aluminum elements	EN	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B2.T-37b	3.5.1-100	C, 3
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-22 Structures and Component Supports - New Fuel Receiving Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-22 Plant-Specific Notes:

1. Concrete elements include foundation, walls, and slabs.
2. Steel elements include beams, columns, baseplates, decking, siding, doors, and embedded steel.
3. Aluminum elements include louvers and screens.

Table 3.5.2-23 Structures and Component Supports - Quench Spray Pump House - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Aluminum elements	EN	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B2.T-37b	3.5.1-100	C, 3
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-23 Structures and Component Supports - Quench Spray Pump House - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-31	3.5.1-046	A, 1
		Reinforced concrete	(E) Air	Cracking; loss of material	Fire Protection (B2.1.15)	VII.G.A-90	3.3.1-060	A, 1
					Structures Monitoring (B2.1.34)	VII.G.A-90	3.3.1-060	A, 1
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-23 Plant-Specific Notes:

1. Concrete elements include beams, columns, foundation, walls, pads, and slabs.
2. Steel elements include beams, columns, doors, ladders, stairs, baseplates, decking, grating, and embedded steel.
3. Aluminum elements include louvers and screens.

Table 3.5.2-24 Structures and Component Supports - Safeguards Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;FB;MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-24 Structures and Component Supports - Safeguards Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;MB;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
Steel elements	EN;MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-24 Plant-Specific Notes:

1. Concrete elements include foundation, internal structural members, walls, pads, hatches, and roof slabs.
2. Steel elements include doors, ladders, stairs, beams, missile shields, baseplates, grating, and embedded steel.

Table 3.5.2-25 Structures and Component Supports - SBO Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Aluminum elements	EN	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B2.T-37b	3.5.1-100	C, 3
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;FLB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-25 Structures and Component Supports - SBO Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FLB;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-31	3.5.1-046	A, 1
Masonry block walls	EN;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-25 Plant-Specific Notes:2

1. Concrete elements include foundation, walls, pads, dikes, and slabs.
2. Steel elements include beams, columns, doors, siding, platforms, baseplates, grating, louvers, screens, and embedded steel.
3. Aluminum elements include louvers and screens.

Table 3.5.2-26 Structures and Component Supports - SBO Structures for Offsite Power - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Carbon fiber reinforced polymer wrap	SS	Polymeric	(E) Air	Hardening or loss of strength; loss of material; cracking or blistering	Structures Monitoring (B2.1.34)	None	None	H, 3
Concrete elements	EN;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-26 Structures and Component Supports - SBO Structures for Offsite Power - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-26 Plant-Specific Notes:

1. Concrete elements include foundations, walls, pads, poles, and slabs.
2. Steel elements include beams, columns, doors, siding, baseplates, decking, poles, and embedded steel.
3. The carbon fiber reinforced polymer wrap is associated with concrete poles.

Table 3.5.2-27 Structures and Component Supports - Security Diesel Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-27 Structures and Component Supports - Security Diesel Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-31	3.5.1-046	A, 1
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-27 Plant-Specific Notes:

1. Concrete elements include beams, columns, walls, slabs, foundation, and pads.
2. Steel elements include beams, columns, baseplates, doors, and embedded steel.

Table 3.5.2-28 Structures and Component Supports - Security Lighting Poles - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	SS	Concrete	(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
Steel elements	SS	Steel	(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-28 Plant-Specific Notes:

1. Concrete elements include pole foundations.
2. Steel elements include poles and baseplates.

Table 3.5.2-29 Structures and Component Supports - Service Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Aluminum elements	EN	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B2.T-37b	3.5.1-100	C, 3
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;FB;FLB; MB;PB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-29 Structures and Component Supports - Service Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB; MB;PB;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-31	3.5.1-046	A, 1
		Reinforced concrete	(E) Air	Cracking; loss of material	Fire Protection (B2.1.15)	VII.G.A-90	3.3.1-060	A, 1
					Structures Monitoring (B2.1.34)	VII.G.A-90	3.3.1-060	A, 1
Doors	EN;FB;FLB; MB;PB	Steel	(E) Air	Loss of material	Fire Protection (B2.1.15)	VII.G.A-21	3.3.1-059	A
			(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A
Masonry block walls	EN;FB;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
		Masonry walls	(E) Air	Cracking; loss of material	Fire Protection (B2.1.15)	VII.G.A-626	3.3.1-179	A
					Masonry Walls (B2.1.33)	VII.G.A-626	3.3.1-179	A
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;FLB;MB; SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-29 Plant-Specific Notes:

1. Concrete elements include beams, columns, foundation, walls, pads, curbs, and slabs.

2. Steel elements include beams, columns, ladders, stairs, baseplates, decking, grating, siding, dikes, and embedded steel.

3. Aluminum elements include louvers and screens.

Table 3.5.2-30 Structures and Component Supports - Service Water Pump House - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A6.TP-248	3.5.1-080	A
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A6.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A6.TP-248	3.5.1-080	A
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A6.TP-261	3.5.1-088	A
			(E) Water – flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	A
			(E) Water – standing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	A
Concrete elements	EN;FLB;MB; SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-34	3.5.1-096	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 1
				Increase in porosity and permeability; loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 1

Table 3.5.2-30 Structures and Component Supports - Service Water Pump House - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FLB;MB; SS	Concrete	(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-34	3.5.1-096	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 1
				Increase in porosity and permeability; loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 1
				Loss of material (spalling, scaling) and cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-36	3.5.1-060	A, 1
			(E) Groundwater	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-107	3.5.1-067	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A6.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-107	3.5.1-067	A, 1

Table 3.5.2-30 Structures and Component Supports - Service Water Pump House - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FLB;MB;SS	Concrete	(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-34	3.5.1-096	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 1
				Increase in porosity and permeability; loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 1
				Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-20	3.5.1-056	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	III.A6.TP-31	3.5.1-046	A, 1
Steel elements	EN;FLT;MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	C, 2
			(E) Air – outdoor	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	C, 2
			(E) Water – flowing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	C, 2
			(E) Water – standing	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	C, 2

Table 3.5.2-30 Plant-Specific Notes:

1. Concrete elements include foundation, beams, columns, walls, slabs, and pads.
2. Steel elements include doors, ladders, stairs, beams, missile shields, baseplates, grating, trash racks, and embedded steel.

Table 3.5.2-31 Structures and Component Supports - Service Water Reservoir - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
				Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-20	3.5.1-056	A, 1
Earthen dike and embankment	BWI;SCW;SS	Earthfill (rip-rap, stone, soil)	(E) Air – outdoor	Loss of material; loss of form	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-22	3.5.1-058	A
			(E) Water – flowing	Loss of material; loss of form	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-22	3.5.1-058	A
			(E) Water – standing	Loss of material; loss of form	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-22	3.5.1-058	A

Table 3.5.2-31 Plant-Specific Notes:

1. Concrete elements represent concrete aprons adjacent to the Service Water Pump House and Service Water Valve House; and the concrete foundations for the spray piping supports.

Table 3.5.2-32 Structures and Component Supports - Service Water Valve House - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A6.TP-248	3.5.1-080	A
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A6.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A6.TP-248	3.5.1-080	A
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A6.TP-261	3.5.1-088	A
Concrete elements	EN;FLB;MB; SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-34	3.5.1-096	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 1
				Increase in porosity and permeability; loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-34	3.5.1-096	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 1
				Increase in porosity and permeability; loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 1
				Loss of material (spalling, scaling) and cracking	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-36	3.5.1-060	A, 1

Table 3.5.2-32 Structures and Component Supports - Service Water Valve House - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FLB;MB; SS	Concrete	(E) Groundwater	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-107	3.5.1-067	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A6.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-104	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A6.TP-107	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A6.TP-220	3.5.1-050	A, 1
						III.A6.TP-25	3.5.1-054	A, 1
					Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-34	3.5.1-096	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-38	3.5.1-059	A, 1
				Increase in porosity and permeability; loss of strength	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-37	3.5.1-061	A, 1
				Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.T-20	3.5.1-056	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	III.A6.TP-31	3.5.1-046	A, 1
Steel elements	EN;MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	C, 2
			(E) Air – outdoor	Loss of material	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35)	III.A6.TP-221	3.5.1-083	C, 2

Table 3.5.2-32 Plant-Specific Notes:

1. Concrete elements include foundation, beams, columns, walls, slabs, and pads.
2. Steel elements include doors, ladders, stairs, beams, baseplates, grating, missile shields, and embedded steel.

Table 3.5.2-33 Structures and Component Supports - Tank Foundations and Missile Barriers - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Caulking and sealants	EN	Elastomer, rubber and other similar materials	(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Compressible seal	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Concrete elements	MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1

Table 3.5.2-33 Structures and Component Supports - Tank Foundations and Missile Barriers - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	MB;SS	Concrete	(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
Grout	SS	Grout	(E) Air – indoor uncontrolled	Reduction in concrete anchor capacity	Structures Monitoring (B2.1.34)	III.B4.TP-42	3.5.1-055	A
			(E) Air – outdoor	Reduction in concrete anchor capacity	Structures Monitoring (B2.1.34)	III.B4.TP-42	3.5.1-055	A
Stainless steel elements	MB	Stainless steel	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B5.T-37b	3.5.1-100	C, 2
			(E) Soil	Loss of material	Structures Monitoring (B2.1.34)	None	None	H, 2
Steel elements	MB	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 3

Table 3.5.2-33 Plant-Specific Notes:

1. Concrete elements include foundation, hatches, and missile barriers.
2. Stainless steel elements include missile barriers.
3. Steel elements include baseplates, missile barriers, and embedded steel.

Table 3.5.2-34 Structures and Component Supports - Turbine Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Aluminum elements	EN	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B2.T-37b	3.5.1-100	C, 3
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;FB;FLB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-34 Structures and Component Supports - Turbine Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-31	3.5.1-046	A, 1
		Reinforced concrete	(E) Air	Cracking; loss of material	Fire Protection (B2.1.15)	VII.G.A-90	3.3.1-060	A, 1
					Structures Monitoring (B2.1.34)	VII.G.A-90	3.3.1-060	A, 1
Doors	EN;FB	Steel	(E) Air	Loss of material	Fire Protection (B2.1.15)	VII.G.A-21	3.3.1-059	A
			(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A
Masonry block walls	EN;FB;SS	Concrete block	(E) Air – indoor uncontrolled	Cracking	Masonry Walls (B2.1.33)	III.A3.T-12	3.5.1-070	A
		Masonry walls	(E) Air	Cracking; loss of material	Fire Protection (B2.1.15)	VII.G.A-626	3.3.1-179	A
					Masonry Walls (B2.1.33)	VII.G.A-626	3.3.1-179	A
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;FLB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-34 Plant-Specific Notes:

1. Concrete elements include beams, columns, foundation, walls, pads, and slabs.

2. Steel elements include beams, columns, ladders, stairs, baseplates, decking, grating, siding, dikes, and embedded steel.

3. Aluminum elements include louvers and screens.

Table 3.5.2-35 Structures and Component Supports - Vaults, Enclosures, and Pits - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;MB;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-35 Structures and Component Supports - Vaults, Enclosures, and Pits - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;MB;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
Steel elements	EN;MB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-35 Plant-Specific Notes:

1. Concrete elements include foundation, walls, beams, hatches, and roof slabs.
2. Steel elements include manhole covers, platforms, ladders, baseplates, and embedded steel.

Table 3.5.2-36 Structures and Component Supports - Waste Disposal Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Aluminum elements	EN	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B2.T-37b	3.5.1-100	C, 3
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-36 Structures and Component Supports - Waste Disposal Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2

Table 3.5.2-36 Plant-Specific Notes:

1. Concrete elements include slabs, curbs, and foundations.
2. Steel elements include beams, columns, baseplates, grating, decking, doors, siding, and embedded steel.
3. Aluminum elements include louvers and screens.

Table 3.5.2-37 Structures and Component Supports - Waste Solidification Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Aluminum elements	EN	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B2.T-37b	3.5.1-100	C, 3
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.A3.TP-261	3.5.1-088	A
Concrete elements	EN;SS	Concrete	(E) Air – indoor uncontrolled	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
			(E) Air – outdoor	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
						III.A3.TP-25	3.5.1-054	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-26	3.5.1-066	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-28	3.5.1-067	A, 1
				Loss of material (spalling, scaling) and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-23	3.5.1-064	A, 1
			(E) Groundwater	Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1

Table 3.5.2-37 Structures and Component Supports - Waste Solidification Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Soil	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Cracking and distortion	Structures Monitoring (B2.1.34)	III.A3.TP-30	3.5.1-044	A, 1
				Cracking; loss of bond; and loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-212	3.5.1-065	A, 1
						III.A3.TP-27	3.5.1-065	A, 1
				Increase in porosity and permeability; cracking; loss of material (spalling, scaling)	Structures Monitoring (B2.1.34)	III.A3.TP-29	3.5.1-067	A, 1
			(E) Water – flowing	Cracking	Structures Monitoring (B2.1.34)	III.A3.TP-204	3.5.1-043	A, 1
				Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A, 1
				Reduction of foundation strength and cracking	Structures Monitoring (B2.1.34)	III.A3.TP-31	3.5.1-046	A, 1
Roofing membrane	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A, 2
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-0772	A, 2

Table 3.5.2-37 Plant-Specific Notes:

1. Concrete elements include walls, slabs, curbs, and foundations.
2. Steel elements include beams, columns, baseplates, siding, decking, doors, and embedded steel.
3. Aluminum elements include louvers and screens.

Table 3.5.2-38 Structures and Component Supports - Component Supports - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Aluminum elements	EN;SS	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B2.T-37b	3.5.1-100	A, 3
						III.B3.T-37b	3.5.1-100	A, 3
						III.B4.T-37b	3.5.1-100	A, 3
						III.B5.T-37b	3.5.1-100	A, 3
Bolting	SS	Stainless steel	(E) Raw water	Loss of preload	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.2.TP-229	3.5.1-087	A
					Structures Monitoring (B2.1.34)	III.B2.TP-261	3.5.1-088	A
						III.B5.TP-261	3.5.1-088	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.B2.TP-248	3.5.1-080	A
						III.B3.TP-248	3.5.1-080	A
						III.B4.TP-248	3.5.1-080	A
						III.B5.TP-248	3.5.1-080	A
					ASME Section XI, Subsection IWF (B2.1.31)	III.B1.2.TP-226	3.5.1-081	A
				Loss of preload	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.2.TP-229	3.5.1-087	A
					Structures Monitoring (B2.1.34)	III.B2.TP-261	3.5.1-088	A
						III.B3.TP-261	3.5.1-088	A
						III.B4.TP-261	3.5.1-088	A
						III.B5.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.B2.TP-248	3.5.1-080	A
						III.B3.TP-248	3.5.1-080	A
						III.B4.TP-248	3.5.1-080	A
						III.B5.TP-248	3.5.1-080	A
					ASME Section XI, Subsection IWF (B2.1.31)	III.B1.2.TP-226	3.5.1-081	A
				Loss of preload	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.2.TP-229	3.5.1-087	A
					Structures Monitoring (B2.1.34)	III.B2.TP-261	3.5.1-088	A
						III.B3.TP-261	3.5.1-088	A
						III.B4.TP-261	3.5.1-088	A
						III.B5.TP-261	3.5.1-088	A

Table 3.5.2-38 Structures and Component Supports - Component Supports - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B1.2.T-25	3.5.1-089	A
						III.B2.T-25	3.5.1-089	A
						III.B3.T-25	3.5.1-089	A
						III.B4.T-25	3.5.1-089	A
						III.B5.T-25	3.5.1-089	A
			(E) Raw water	Loss of preload	Structures Monitoring (B2.1.34)	III.B2.TP-261	3.5.1-088	A
						III.B5.TP-261	3.5.1-088	A
			(E) Water – flowing	Loss of material	ASME Section XI, Subsection IWF (B2.1.31)	III.A6.TP-221	3.5.1-083	E, 5
					Structures Monitoring (B2.1.34)	III.A6.TP-221	3.5.1-083	E, 6
Grout	SS	Grout	(E) Air – indoor uncontrolled	Reduction in concrete anchor capacity	Structures Monitoring (B2.1.34)	III.B1.2.TP-42	3.5.1-055	A
						III.B2.TP-42	3.5.1-055	A
						III.B3.TP-42	3.5.1-055	A
						III.B4.TP-42	3.5.1-055	A
						III.B5.TP-42	3.5.1-055	A
			(E) Air – outdoor	Reduction in concrete anchor capacity	Structures Monitoring (B2.1.34)	III.B1.2.TP-42	3.5.1-055	A
						III.B2.TP-42	3.5.1-055	A
						III.B3.TP-42	3.5.1-055	A
						III.B4.TP-42	3.5.1-055	A
						III.B5.TP-42	3.5.1-055	A
Sliding surfaces	SS	Lubrite®	(E) Air – indoor uncontrolled	Loss of mechanical function	Structures Monitoring (B2.1.34)	III.B2.TP-46	3.5.1-074	A
					ASME Section XI, Subsection IWF (B2.1.31)	III.B1.2.TP-45	3.5.1-075	A
Spring hangers; guides; stops	SS	Steel	(E) Air – indoor uncontrolled	Loss of mechanical function	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.2.T-28	3.5.1-057	A
					Structures Monitoring (B2.1.34)	III.B1.2.T-28	3.5.1-057	E, 4
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B1.2.T-25	3.5.1-089	A
						III.B2.T-25	3.5.1-089	A
Stainless steel elements	SS	Stainless steel	(E) Air	Loss of material; cracking	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.2.T-36b	3.5.1-099	A, 2
					Structures Monitoring (B2.1.34)	III.B2.T-37b	3.5.1-100	A, 2
						III.B4.T-37b	3.5.1-100	A, 2

Table 3.5.2-38 Structures and Component Supports - Component Supports - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Steel elements	EN;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.2.T-24	3.5.1-091	A, 1
					Structures Monitoring (B2.1.34)	III.B2.TP-43	3.5.1-092	A, 1
						III.B3.TP-43	3.5.1-092	A, 1
						III.B4.TP-43	3.5.1-092	A, 1
						III.B5.TP-43	3.5.1-092	A, 1
			(E) Air – outdoor	Loss of material	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.2.T-24	3.5.1-091	A, 1
					Structures Monitoring (B2.1.34)	III.B2.TP-43	3.5.1-092	A, 1
						III.B3.TP-43	3.5.1-092	A, 1
						III.B4.TP-43	3.5.1-092	A, 1
						III.B5.TP-43	3.5.1-092	A, 1
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B1.2.T-25	3.5.1-089	A, 1
						III.B2.T-25	3.5.1-089	A, 1
						III.B3.T-25	3.5.1-089	A, 1
						III.B4.T-25	3.5.1-089	A, 1
						III.B5.T-25	3.5.1-089	A, 1
			(E) Water – flowing	Loss of material	ASME Section XI, Subsection IWF (B2.1.31)	III.A6.TP-221	3.5.1-083	E, 1, 5
					Structures Monitoring (B2.1.34)	III.A6.TP-221	3.5.1-083	E, 1, 6
Vibration isolation elements	SS	Non-metallic (e.g., rubber)	(E) Air – indoor uncontrolled	Reduction or loss of isolation function	Structures Monitoring (B2.1.34)	III.B4.TP-44	3.5.1-094	A

Table 3.5.2-38 Plant-Specific Notes:

1. Steel elements include support members, bearing plates, baseplates, connections, cable trays, conduits, instrument racks, and structural frames.
2. Stainless steel elements include support members.
3. Aluminum elements include support members, cable trays, and conduits.
4. The Structures Monitoring (B2.1.34) program instead of the ASME Section XI, Subsection IWF (B2.1.31) program will manage the aging effects applicable to this component type, material, and environment combination for non-ASME supports.

5. The ASME Section XI, Subsection IWF (B2.1.31) program instead of the Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35) program will manage the aging effects applicable to this component type, material, and environment combination for ASME Class 2 and Class 3 supports.

6. The Structures Monitoring (B2.1.34) program instead of the Inspection of Inspection of Water-Control Structures Associated with Nuclear Power Plants (B2.1.35) program will manage the aging effects applicable to this component type, material, and environment combination for non-ASME supports.

Table 3.5.2-39 Structures and Component Supports - Miscellaneous Structural Commodities - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.B3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.B3.TP-261	3.5.1-088	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.B3.TP-248	3.5.1-080	A
				Loss of preload	Structures Monitoring (B2.1.34)	III.B3.TP-261	3.5.1-088	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B3.T-25	3.5.1-089	A
Electrical Enclosures	EN;LB;SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.B3.TP-43	3.5.1-092	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.B3.TP-43	3.5.1-092	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B3.T-25	3.5.1-089	C

Table 3.5.2-39 Structures and Component Supports - Miscellaneous Structural Commodities - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Fireproofing and fire barriers	EN;FB;FLB	Cementitious coatings (Pyrocrete, BIO™ K-10 Mortar, Cafecote, and other similar materials)	(E) Air	Cracking; Loss of material	Fire Protection (B2.1.15)	VII.G.A-806	3.3.1-268	A, 1, 2
		Elastomer	(E) Air	Hardening, loss of strength, shrinkage	Fire Protection (B2.1.15)	VII.G.A-19	3.3.1-057	A, 1
		Silicates (Marinite®, Kaowool™, Cerafiber®, Cera® blanket, or other similar materials)	(E) Air	Cracking; Loss of material	Fire Protection (B2.1.15)	VII.G.A-807	3.3.1-269	A, 1, 2
		Stainless steel	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B2.T-37b	3.5.1-100	C, 1
		Subliming compounds (Thermo-Lag®, Darmatt™, 3M™ Interam™, and other similar materials)	(E) Air	Cracking; Loss of material	Fire Protection (B2.1.15)	VII.G.A-805	3.3.1-267	A, 1, 2
Penetration seals	EN;FB;FLB;PB	Elastomer	(E) Air	Hardening, loss of strength, shrinkage	Fire Protection (B2.1.15)	VII.G.A-19	3.3.1-057	A
		Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Groundwater	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Soil	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A

Table 3.5.2-39 Structures and Component Supports - Miscellaneous Structural Commodities - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Penetration sleeves	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.B3.TP-43	3.5.1-092	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.B3.TP-43	3.5.1-092	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B3.T-25	3.5.1-089	C
Seismic gap covers	EN;FB	Aluminum	(E) Air	Loss of material; cracking	Structures Monitoring (B2.1.34)	III.B2.T-37b	3.5.1-100	C
		Elastomer	(E) Air	Hardening, loss of strength, shrinkage	Fire Protection (B2.1.15)	VII.G.A-19	3.3.1-057	C
		Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
		Steel	(E) Air	Loss of material	Fire Protection (B2.1.15)	VII.G.A-21	3.3.1-059	C
			(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A
			(E) Air – outdoor	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A
Seismic gap filler material	EN	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A

Table 3.5.2-39 Plant-Specific Notes:

1. Fireproofing and fire barriers include fire stops, fire wraps, fire barrier seals, coatings, and radiant energy shields.
2. Change in material properties is an aging effect not being managed.

Table 3.5.2-40 Structures and Component Supports - NSSS Supports - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	High-strength steel	(E) Air	Cracking	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.1.TP-41	3.5.1-068	A
				Loss of preload	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.1.TP-229	3.5.1-087	A
		Stainless steel	(E) Air	Loss of preload	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.1.TP-229	3.5.1-087	A
				Loss of material; cracking	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.2.T-36b	3.5.1-099	A
		Steel	(E) Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.1.TP-226	3.5.1-081	A
				Loss of preload	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.1.TP-229	3.5.1-087	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B1.1.T-25	3.5.1-089	A
Grout	SS	Grout	(E) Air – indoor uncontrolled	Reduction in concrete anchor capacity	Structures Monitoring (B2.1.34)	III.B1.1.TP-42	3.5.1-055	A
Sliding surfaces	SS	Lubrite®	(E) Air – indoor uncontrolled	Loss of mechanical function	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.1.TP-45	3.5.1-075	A
Spring hangers; guides; stops	SS	Steel	(E) Air – indoor uncontrolled	Loss of mechanical function	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.1.T-28	3.5.1-057	A
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B1.1.T-25	3.5.1-089	A
Stainless steel elements	SS	Stainless steel	(E) Air	Loss of material; cracking	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.1.T-36b	3.5.1-099	A, 2
Steel elements	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWF (B2.1.31)	III.B1.1.T-24	3.5.1-091	A, 1
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B1.1.T-25	3.5.1-089	A, 1

Table 3.5.2-40 Plant-Specific Notes:

1. Steel elements include support members, bearing plates, baseplates, and connections, including maraging steel.
2. Stainless steel elements include support members and dust covers.

Tables 3.5.2-1 through 3.5.2-40 Industry Standard Notes:

A. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

B. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.

C. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

D. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to the NUREG-2191 AMP.

E. Consistent with NUREG-2191 item for 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.

G. Environment not in NUREG-2191 for this component and material.

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.

J. Neither the component nor the material and environment combination is evaluated in NUREG-2191.

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3.6 AGING MANAGEMENT OF ELECTRICAL AND INSTRUMENTATION AND CONTROLS

3.6.1 INTRODUCTION

This section provides the results of the aging management review for components and commodities identified in Section 2.5.1, Electrical Component Groups as being subject to aging management review. Components and commodities addressed in this section are described in the indicated sections.

- Cables And Connections (Section 2.5.1.1)
- High Voltage Insulators (Section 2.5.1.2)
- Metal Enclosed Bus (Section 2.5.1.3)

3.6.2 RESULTS

The following tables summarize the results of the aging management review for Electrical and Instrumentation and Controls.

- Table 3.6.2-1, Electrical and Instrumentation and Controls - Cables And Connections - Aging Management Evaluation
- Table 3.6.2-2, Electrical and Instrumentation and Controls - High Voltage Insulators - Aging Management Evaluation
- Table 3.6.2-3, Electrical and Instrumentation and Controls - Metal Enclosed Bus - Aging Management Evaluation

3.6.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.6.2.1.1 Cables And Connections

Materials

The materials of construction for the cables and connections subcomponents are:

- Aluminum
- Electrical insulation: Bakelite®; phenolic melamine or ceramic; molded polycarbonate; other
- Various metals used for electrical connections
- Various metals used for electrical contacts
- Various organic polymers such as EPR, SR, EPDM, XLPE, butyl rubber, and combined thermoplastic jacket/insulation shield

Environment

The cables and connections subcomponents are exposed to the following environments:

- Adverse localized environment caused by heat, radiation, or moisture
- Adverse localized environment caused by significant moisture
- Air – indoor controlled
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage

Aging Effects Requiring Management

The following aging effects, associated with the cables and connections subcomponents, require management:

- Increased electrical resistance of connection
- Reduced electrical insulation resistance or degraded dielectric strength

Aging Management Programs

The following aging management programs manage the aging effects for the cables and connections subcomponents:

- Boric Acid Corrosion (B2.1.4)
- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.37)
- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (B2.1.38)
- Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.39)
- Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.40)
- Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.41)
- Fuse Holders (B2.1.43)
- Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.44)

3.6.2.1.2 High Voltage Insulators

Materials

The materials of construction for the high voltage insulators subcomponents are:

- Porcelain, malleable iron, aluminum, galvanized steel, cement, toughened glass, polymers silicone rubber, fiberglass, aluminum alloy

Environment

The high voltage insulators subcomponents are exposed to the following environments:

- Air – outdoor

Aging Effects Requiring Management

The following aging effects, associated with the high voltage insulators subcomponents, require management:

- Loss of material
- Reduced electrical insulation resistance

Aging Management Programs

The following aging management programs manage the aging effects for the high voltage insulators subcomponents:

- High-Voltage Insulators (B2.1.45)

3.6.2.1.3 Metal Enclosed Bus

Materials

The materials of construction for the metal enclosed bus subcomponents are:

- Aluminum
- Elastomer
- Porcelain
- Steel
- Thermo-plastic organic polymers
- Various metals used for electrical bus and connections
- Xenoy®

Environment

The metal enclosed bus subcomponents are exposed to the following environments:

- Air – indoor controlled
- Air – indoor uncontrolled
- Air – outdoor

Aging Effects Requiring Management

The following aging effects, associated with the metal enclosed bus subcomponents, require management:

- Increased electrical resistance of connection
- Loss of material
- Reduced electrical insulation resistance
- Surface cracking, crazing, scuffing, dimensional change, shrinkage, discoloration, hardening, loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the metal enclosed bus subcomponents:

- Metal-Enclosed Bus (B2.1.42)

3.6.2.2 Further Evaluation of Aging Management as Recommended by NUREG-2192

NUREG-2192 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 evaluations are addressed in the following sections.

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.

[3.6.1-001] - Environmental qualification is a time-limited aging analysis (TLAA) as defined in 10 CFR 54.3. The evaluation of this TLAA is addressed in Section 4.4, Environmental Qualification of Electric Equipment.

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).

[3.6.1-029] [3.6.1-030] [3.6.1-031] - Reduced insulation resistance and loss of material for cable bus can be caused by age related degradation. This issue is not applicable because North Anna does not use cable bus.

3.6.2.2.3 Loss of Material Due to Wind-Induced Abrasion, Loss of Conductor Strength Due to Corrosion, and Increased Resistance of Connection Due to Oxidation or Loss of Preload for Transmission Conductors, Switchyard Bus, and Connections

Loss of material due to wind-induced abrasion, loss of conductor strength due to corrosion, and increased resistance of connection due to oxidation or loss of preload could occur in transmission conductors and connections, and in switchyard bus and connections. The GALL SLR Report recommends further evaluation of a plant-specific AMP to demonstrate that this aging effect is adequately managed. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

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 switchyard bus, bus connections, transmission conductors and connections are those credited for recovery of offsite power following a station blackout event. Overhead cables credited for recovery of offsite power following a station blackout event operate at distribution voltage (34.5 kV) instead of transmission voltage (>69 kV), and would typically be referred to as overhead conductors and overhead conductor connections. However, for consistency in terminology, they will be referred to as transmission conductors and transmission connections.

[3.6.1-004] - NAPS has no in-scope ACSR transmission conductors in the Transmission Conductor component group. The in-scope transmission conductors at NAPS are bare 545.6 MCM Aluminum Conductor Aluminum Reinforced conductors and are not subject to corrosion that requires aging management.

[3.6.1-005] - Increased electrical resistance of connection due to oxidation or loss of pre-load is not applicable for aluminum transmission connectors exposed to outdoor air environments in the Transmission Connections component group at NAPS.

Transmission conductor connections are treated with corrosion inhibitors to avoid connection oxidation. Connections are assembled using aluminum bolts and nuts. The connections are torqued when installed to avoid loss of pre-load.

Based on design and confirmed by operating experience, oxidation and loss of preload are not applicable aging mechanisms for transmission conductor connections at North Anna.

[3.6.1-006] - Loss of material due to wind induced abrasion and increased electrical resistance of connection due to oxidation or loss of pre-load are not applicable for aluminum and stainless steel components exposed to outdoor air environments in the switchyard bus and connections component group for NAPS.

NAPS uses aluminum tubular switchyard bus and aluminum angle switchyard bus supported by active components and station post insulators mounted on steel structures in concrete foundations. Connections between switchyard bus and active components such as circuit breakers are either directly terminated or connected by short lengths of flexible aluminum conductors that are not typically subject to vibration under wind loading. Switchyard bus is not subject to abrasion induced by wind loading due to its rigid mounting.

NAPS is located in a largely agricultural area on a manmade, fresh water lake. Salt spray and salt coating have not been experienced on switchyard components at NAPS. There are no nearby industrial facilities that produce airborne industrial effluents affecting NAPS. Aluminum cable and bus material does not experience any appreciable aging effects in this environment.

Buses 3, 4, and 5 in the North Anna 34.5 kV switchyard were rebuilt in the 2003 to 2007 time period. The electrical bus, disconnect switches, circuit breakers, connecting bare cable, and terminations were replaced with new equipment. Also, the underground insulated cables that connect from the 34.5 kV circuit breakers to the RSSTs were replaced in the same time period.

Aluminum switchyard bus and cable connections are treated with corrosion inhibitors to avoid connection oxidation. Connection hardware is either aluminum or stainless steel. Connections that are assembled using either aluminum or stainless steel bolts and nuts include lock washers and are torqued to prevent loss of preload.

Based on design and confirmed by operating experience, wind-induced abrasion and increased resistance of connection due to oxidation and loss of preload are not applicable aging mechanisms for switchyard bus and connections at North Anna.

[3.6.1-007] - Loss of material due to wind-induced abrasion is not applicable for aluminum transmission conductors exposed to outdoor air environments in the Transmission Conductors component group for NAPS.

Transmission conductor vibration, or sway, could be caused by wind loading. Experience has shown that transmission conductors do not normally swing significantly. When transmission conductors do swing due to a substantial wind, they do not continue to swing for very long once the wind has subsided. Wind loading that can cause a transmission conductor to vibrate or sway is considered in design and installation. Transmission conductors at NAPS in-scope of subsequent license renewal operate at distribution voltages (34.5 kV) instead of transmission voltages. They are installed with shorter spans, at lower elevations, and with less sag than transmission conductors. Thus, they tend to be less affected by wind loading than transmission conductors.

Based on design and confirmed by operating experience, wind-induced abrasion is not an applicable aging mechanism for transmission conductors at North Anna.

3.6.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

Quality Assurance provisions applicable to subsequent license renewal are discussed in Appendix B1.3, Quality Assurance Program and Administrative Controls.

3.6.2.2.5 Ongoing Review of Operating Experience

The operating experience process and acceptance criteria are described in Appendix B1.4, Operating Experience.

3.6.2.3 Aging Management Review Results Not Consistent With or Not Addressed in the Generic Aging Lessons Learned for Subsequent License Renewal Report

Fuse Holders – Not Part of Active Equipment (Metallic Clamps and Insulation Material)

The individual fuse holders not part of active equipment subject to aging management review were identified from a review of electrical drawings. The results of this review identified fuse holders in 19 enclosures at NAPS that require aging management review. Eleven of these enclosures are located in the main control room complex in an air–indoor controlled environment. The remaining fuse holders are located in eight enclosures (four enclosures per unit) in the control rod drive rooms. An evaluation of aging effects determined that fuse holders in the eleven enclosures located in the main control room complex are not susceptible to the aging effects discussed in NUREG-2191. The evaluation of aging effects for these fuse holders is discussed below.

Main Control Room Complex

Chemical Contamination, Corrosion, and Oxidation (Metallic Clamps)

Each of the subject fuse holders at NAPS is located in the control room complex in an air-indoor controlled environment that does not subject them to environmental aging mechanisms. The environment inside the room is air-conditioned by a ventilation system, thus the fuse holders do not experience high relative humidity during normal conditions. There are no sources of chemicals in the vicinity of the fuse holder enclosures during normal conditions.

A walkdown of the electrical enclosures containing the subject fuse holders confirmed that the operating conditions for these fuse holders are clean and dry, with no evidence of moisture intrusion, chemical contamination, oxidation, or corrosion. Therefore, chemical contamination, corrosion, and oxidation are not considered applicable aging mechanisms for these fuse holders.

Ohmic Heating, Thermal Cycling, and Electrical Transients (Metallic Clamps)

Fuse holders for circuits that carry significant current in power applications could potentially be exposed to thermal fatigue in the form of high resistance caused by thermal cycling and ohmic heating. Instrumentation and control power circuits characteristically operate at low currents where no appreciable thermal cycling or ohmic heating occurs.

The subject fuse holders at NAPS are for multiplexers and solenoid operated valves. These loads are instrumentation and control circuits that operate at low power where no appreciable thermal cycling or ohmic heating occurs. Therefore, electrical and thermal cycling is not considered an applicable aging mechanism for these fuse holders.

Mechanical stress due to forces associated with electrical faults and transients is mitigated by the fast action of the circuit protective devices at high currents. Also, mechanical stress due to electrical faults is not considered a credible aging mechanism since such faults are infrequent and random in nature.

Frequent Manipulation and Vibration (Metallic Clamps)

Wear and fatigue are caused by repeated insertion and removal of fuses. The fuses in these fuse holders are not subject to frequent manipulation (i.e., removal and reinsertion) because they are neither tagging nor isolation points which support periodic testing or preventive maintenance. Additionally, if fuses are manipulated for non-routine inspection or maintenance, proceduralized good work practices would identify any abnormal condition such as loose or corroded fuse clips.

These subject fuse holders are located in enclosures that are not mounted on rotating or reciprocating equipment such as compressors, fans, or pumps. Because the enclosures are mounted with no attached sources of vibration, vibration is not an applicable aging mechanism. Therefore, the metallic clamps of these fuse holders will not exhibit the aging effects/mechanisms of fatigue due to frequent manipulation or vibration.

Reduced Electrical Insulation Resistance (Insulation Material)

The subject fuse holders are mounted inside enclosed boxes in the control room complex. These areas are air conditioned by permanent ventilation units maintaining the fuse holders in a controlled temperature, low humidity environment during normal conditions. The fuse holders are not subject to outside weather conditions and are further protected from incidental exposure to moisture by being mounted inside an enclosure. The control room is a mild environment and does not experience elevated levels of radiation. The fuse holders are not exposed to solar radiation and are protected from exposure to light fixtures by their enclosures. Therefore, the insulation material of these fuse holders will not exhibit the aging effects of reduced electrical insulation resistance due to thermal/thermoxidative degradation of organics, radiolysis, and photolysis of organics, radiation-induced oxidation, and moisture intrusion.

Based on installed location, design configuration, operating service conditions, and operating experience, fuse holders inside the eleven enclosures located in the NAPS main control room complex are not susceptible to the aging effects and mechanisms associated with metallic clamps and insulating material. Therefore, aging management activities are not required for these fuse holders at NAPS.

Control Rod Drive Rooms

The eight enclosures (four enclosures in each unit) in the control rod drive rooms house 52 fuse holders that power the pressurizer heaters. Fuses in these fuse holders are rated at 90A and carry significant current that can potentially expose the fuse holder metallic clamps to thermal fatigue in the form of high resistance caused by thermal cycling and ohmic heating. Therefore, aging management activities are required for these 52 fuse holders.

Based on installed location, design configuration, operating service conditions, and operating experience, fuse holders inside the eight enclosures located in the NAPS control rod drive rooms are susceptible to the aging effects and mechanisms associated with metallic clamps. Therefore, aging management activities are required for these fuse holders at NAPS. These fuse holders will be age managed by the Fuse Holders (B2.1.43) program.

Results Tables: Electrical and Instrumentation and Controls Commodity Groups

Table 3.6.1 Summary of Aging Management Programs for the Electrical Components Evaluated in Chapter VI of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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 Electric Equipment, for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1)(i) and (ii). See AMP X.E1, Environmental Qualification (EQ) of Electric Equipment, of this report for meeting the requirements of 10 CFR 54.21(c)(1)(i)-(iii).	Yes, TLAA (SRP-SLR Section 3.6.2.2.1)	Environmental Qualification is a TLAA. See further evaluation in Section 3.6.2.2.1.
3.6.1-002	High-voltage electrical insulators composed of porcelain; malleable iron; aluminum; galvanized steel; cement; toughened glass; polymers; silicone rubber; fiber glass, aluminum alloy exposed to air – outdoor	Loss of material due to mechanical wear caused by movement of transmission conductors due to significant wind, and wind-driven particles impacting surfaces	AMP XI.E7, High-Voltage Insulators	No	Consistent with NUREG-2191.

Table 3.6.1 Summary of Aging Management Programs for the Electrical Components Evaluated in Chapter VI of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.6.1-003	High-voltage electrical insulators composed of porcelain; malleable iron; aluminum; galvanized steel; cement; toughened glass; polymers; silicone rubber; fiber glass, aluminum alloy exposed to air – outdoor	Reduced electrical insulation resistance due to presence of salt deposits, surface contamination, or peeling of silicone rubber sleeves for polymer insulators	AMP XI.E7, High-Voltage Insulators	No	Consistent with NUREG-2191.
3.6.1-004	Transmission conductors composed of aluminum; steel exposed to air – outdoor	Loss of conductor strength due to corrosion	A plant-specific aging management program is to be evaluated for ACSR	Yes (SRP-SLR Section 3.6.2.2.3)	Not applicable. NAPS has no in-scope transmission conductors composed of aluminum and steel exposed to an air-outdoor environment. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.6.2.2.3.
3.6.1-005	Transmission connectors composed of aluminum; steel exposed to air – outdoor	Increased electrical resistance of connection due to oxidation or loss of pre-load	A plant-specific aging management program is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.3)	The NUREG-2191 aging effect of increased electrical resistance of connection for aluminum transmission connectors exposed to an air-outdoor environment is not applicable to NAPS. See further evaluation in Section 3.6.2.2.3.
3.6.1-006	Switchyard bus and connections composed of aluminum; copper; bronze; stainless steel; galvanized steel exposed to air – outdoor	Loss of material due to wind-induced abrasion; Increased electrical resistance of connection due to oxidation or loss of pre-load	A plant-specific aging management program is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.3)	The NUREG-2191 aging effect of loss of material and increased electrical resistance of connection for aluminum and stainless steel exposed to an air-outdoor environment is not applicable to NAPS. See further evaluation in Section 3.6.2.2.3.
3.6.1-007	Transmission conductors composed of aluminum; steel exposed to air – outdoor	Loss of material due to wind-induced abrasion	A plant-specific aging management program is to be evaluated for All Aluminum Conductor (AAC), ACAR and ACSR	Yes (SRP-SLR Section 3.6.2.2.3)	The NUREG-2191 aging effect of loss of material for aluminum and steel transmission conductors exposed to an air-outdoor environment is not applicable to NAPS. See further evaluation in Section 3.6.2.2.3.

Table 3.6.1 Summary of Aging Management Programs for the Electrical Components Evaluated in Chapter VI of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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, SR, EPDM, XLPE) 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.
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 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.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.

Table 3.6.1 Summary of Aging Management Programs for the Electrical Components Evaluated in Chapter VI of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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. Reduced electrical insulation resistance or degraded dielectric strength is managed by the Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.40) program, the Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.41) program or the Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.39) program.
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 or loss of strength due to elastomer degradation	AMP XI.E4, Metal Enclosed Bus, or AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191. Surface cracking, crazing, scuffing, dimensional change (e.g. “ballooning” and “necking”), shrinkage, discoloration, hardening or loss of strength of metal enclosed bus enclosure assemblies composed of elastomers exposed to an air-indoor controlled, air-indoor uncontrolled, or air-outdoor environment is managed by the Metal Enclosed Bus (B2.1.42) program.

Table 3.6.1 Summary of Aging Management Programs for the Electrical Components Evaluated in Chapter VI of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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.
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.
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. Loss of material due to general, pitting, or crevice corrosion of metal enclosed bus enclosure assemblies composed of steel exposed to an air-indoor uncontrolled environment is managed by the Metal Enclosed Bus (B2.1.42) program.
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. Loss of material due to general, pitting, or crevice corrosion of metal enclosed bus enclosure assemblies composed of aluminum exposed to an air-outdoor environment is managed by the Metal Enclosed Bus (B2.1.42) program.

Table 3.6.1 Summary of Aging Management Programs for the Electrical Components Evaluated in Chapter VI of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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 aging management program is required for those applicants who can demonstrate these fuse holders are located in an environment that does not subject them to environmental aging mechanisms and effects due to chemical contamination, corrosion, and oxidation.	No	Consistent with NUREG-2191.
3.6.1-017	Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air-indoor controlled or uncontrolled	Increased electrical resistance of connection due to fatigue from ohmic heating, thermal cycling, electrical transients	AMP XI.E5, Fuse Holders - No aging management program is required for those applicants who can demonstrate these fuse holders are not subject to fatigue due to ohmic heating, thermal cycling, electrical transients.	No	Consistent with NUREG-2191.

Table 3.6.1 Summary of Aging Management Programs for the Electrical Components Evaluated in Chapter VI of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.6.1-018	Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air – indoor controlled or uncontrolled	Increased electrical resistance of connection due to fatigue caused by frequent fuse removal/manipulation or vibration	AMP XI.E5, Fuse Holders - No aging management program is required for those applicants who can demonstrate these fuse holders are not subject to fatigue caused by frequent fuse removal/manipulation or vibration.	No	Consistent with NUREG-2191.
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.
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.
3.6.1-021	Transmission conductors composed of aluminum exposed to air – outdoor	Loss of conductor strength due to corrosion	None - for ACAR and All Aluminum Conductor (AAC)	No	Consistent with NUREG-2191.

Table 3.6.1 Summary of Aging Management Programs for the Electrical Components Evaluated in Chapter VI of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.6.1-022	Fuse holders (not part of active equipment): insulation material composed of electrical insulation material: Bakelite®; phenolic melamine or ceramic; molded polycarbonate, and other, exposed to air – indoor controlled or uncontrolled	Reduced electrical insulation resistance due to thermal/thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	AMP XI.E5, Fuse Holders - No aging management program is required for those applicants who can demonstrate these fuse holders are located in an environment that does not subject them to environmental aging mechanisms	No	Consistent with NUREG-2191.
3.6.1-023	Metal enclosed bus: external surface of enclosure assemblies. Galvanized steel; aluminum. air – indoor controlled or uncontrolled	None	None	No	Consistent with NUREG-2191.
3.6.1-024	Metal enclosed bus: external surface of enclosure assemblies. Steel air – indoor controlled	None	None	No	Consistent with NUREG-2191.
3.6.1-027	Cable bus: external surface of enclosure assemblies galvanized steel; aluminum; air – indoor controlled or uncontrolled	None	None	No	Not applicable. NAPS has no in-scope cable bus. The associated NUREG-2191 aging items are not used.

Table 3.6.1 Summary of Aging Management Programs for the Electrical Components Evaluated in Chapter VI of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.6.1-029	Cable bus: electrical insulation; insulators – exposed to air – indoor controlled or uncontrolled, air – outdoor	Reduced electrical insulation resistance due to degradation caused thermal/thermoxidative degradation of organics and photolysis (UV sensitive materials only) of organics, moisture/debris intrusion and ohmic heating	A plant-specific aging management program is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.2)	Not applicable. NAPS has no in-scope cable bus. The associated NUREG-2191 aging items are not used.
3.6.1-030	Cable bus: external surface of enclosure assemblies composed of steel exposed to air – indoor uncontrolled or air – outdoor	Loss of material due to general, pitting, crevice corrosion	A plant-specific aging management program is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.2)	Not applicable. NAPS has no in-scope cable bus. The associated NUREG-2191 aging items are not used.
3.6.1-031	Cable bus external surface of enclosure assemblies composed of galvanized steel; aluminum exposed to air – outdoor	Loss of material due to general, pitting, crevice corrosion	A plant-specific aging management program is to be evaluated	Yes (SRP-SLR Section 3.6.2.2.2)	Not applicable. NAPS has no in-scope cable bus. The associated NUREG-2191 aging items are not used.
3.6.1-032	Cable bus: external surface of enclosure assemblies: composed of steel; air – indoor controlled	None	None	No	Not applicable. NAPS has no in-scope cable bus. The associated NUREG-2191 aging items are not used.

Results Tables: Electrical and Instrumentation and Controls AMR Results

Table 3.6.2-1 Electrical and Instrumentation and Controls - Cables And Connections - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Cable Connections (metallic parts)	CE	Various metals used for electrical contacts	(E) Air – indoor controlled	Increased electrical resistance of connection	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.44)	VI.A.LP-30	3.6.1-019	A
			(E) Air – indoor uncontrolled	Increased electrical resistance of connection	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.44)	VI.A.LP-30	3.6.1-019	A
			(E) Air – outdoor	Increased electrical resistance of connection	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B2.1.44)	VI.A.LP-30	3.6.1-019	A
Connector Contacts for Electrical Connections Exposed to Borated Water Leakage	CE	Various metals used for electrical contacts	(E) Air with borated water leakage	Increased electrical resistance of connection	Boric Acid Corrosion (B2.1.4)	VI.A.LP-36	3.6.1-020	A
Fuse Holder - Not Part of Active Equipment (Insulation Material)	IN	Electrical insulation: Bakelite®; phenolic melamine or ceramic; molded polycarbonate; other	(E) Air – indoor controlled	Reduced electrical insulation resistance	None	VI.A.LP-24	3.6.1-022	I, 5
			(E) Air – indoor uncontrolled	Reduced electrical insulation resistance	Fuse Holders (B2.1.43)	VI.A.LP-24	3.6.1-022	A
Fuse Holder - Not Part of Active Equipment (Metallic Clamps)	CE	Various metals used for electrical connections	(E) Air – indoor controlled	Increased electrical resistance of connection	None	VI.A.L-07	3.6.1-017	I, 6
						VI.A.LP-31	3.6.1-018	I, 6
			(E) Air – indoor uncontrolled	Increased electrical resistance of connection	Fuse Holders (B2.1.43)	VI.A.LP-23	3.6.1-016	A
						VI.A.L-07	3.6.1-017	A
						VI.A.LP-31	3.6.1-018	A

Table 3.6.2-1 Electrical and Instrumentation and Controls - Cables And Connections - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Insulation Material for Electrical Cable and Connections Used in Instrumentation Circuits	IN	Various organic polymers (e.g., EPR, SR, EPDM, XLPE)	(E) 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 (B2.1.38)	VI.A.LP-34	3.6.1-009	A
Insulation Material for Electrical Cables and Connections	IN	Various organic polymers (e.g., EPR, SR, EPDM, XLPE)	(E) 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 (B2.1.37)	VI.A.LP-33	3.6.1-008	A
Insulation Material for Inaccessible or Below Ground Instrumentation and Control Cable	IN	Various organic polymers such as EPR, SR, EPDM, XLPE, butyl rubber, and combined thermoplastic jacket/insulation shield	(E) 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 (B2.1.40)	VI.A.LP-35b	3.6.1-010	A
Insulation Material for Inaccessible or Below Ground Low Voltage Power Cable	IN	Various organic polymers such as EPR, SR, EPDM, XLPE, butyl rubber, and combined thermoplastic jacket/insulation shield	(E) 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 (B2.1.41)	VI.A.LP-35c	3.6.1-010	A

Table 3.6.2-1 Electrical and Instrumentation and Controls - Cables And Connections - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Insulation Material for Inaccessible or Below Ground Medium Voltage Cable	IN	Various organic polymers such as EPR, SR, EPDM, XLPE, butyl rubber, and combined thermoplastic jacket/insulation shield	(E) 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 (B2.1.39)	VI.A.LP-35a	3.6.1-010	A
Switchyard Bus and Connections	CE	Aluminum	(E) Air – outdoor	None	None	VI.A.LP-39	3.6.1-006	I, 1
Transmission Conductors	CE	Aluminum	(E) Air – outdoor	None	None	VI.A.LP-47	3.6.1-007	I, 2
						VI.A.LP-46	3.6.1-021	I, 4
Transmission Connectors	CE	Aluminum	(E) Air – outdoor	None	None	VI.A.LP-48	3.6.1-005	I, 3

Table 3.6.2-1 Plant-Specific Notes:

1. Loss of material and increased resistance of connection are not applicable aging effects for switchyard bus and connections at NAPS. The in-scope switchyard bus and connections are subject to neither wind induced abrasion nor oxidation or loss of pre-load.

2. Loss of material is not an applicable aging effect for transmission conductors at NAPS. The in-scope transmission conductors are not subject to wind induced abrasion.

3. Increased resistance of connection is not an applicable aging effect for transmission connections at NAPS. The in-scope transmission connections are not subject to oxidation or loss of pre-load.

4. Loss of conductor strength is not an applicable aging effect for transmission conductors at NAPS. The in-scope transmission conductors are aluminum conductor aluminum alloy reinforced transmission conductors.

5. Reduced electrical insulation resistance due to thermal/thermoxidative degradation of organics, radiolysis, and photolysis of organics, radiation-induced oxidation, and moisture intrusion are not aging effects for electrical insulation associated with fuse holders that are not part of active equipment at NAPS. The fuse holders are contained within enclosed boxes and located in an air-indoor controlled environment. The fuse holders are not subject to outside weather conditions and are further protected from incidental exposure to moisture by being mounted inside an enclosure. These enclosures are within mild environments that do not experience elevated levels of radiation. The fuse holders are not exposed to solar radiation and are protected from exposure to light fixtures by their enclosures.

6. Increased electrical resistance of connection due to fatigue caused by frequent fuse removal/manipulation or vibration, or due to fatigue due to ohmic heating, thermal cycling, or electrical transients is not an aging effect for fuse holders not part of active equipment at NAPS. Fuse holders not part of active equipment are located in an air-indoor controlled environment and supply low power and instrumentation circuits that are constantly energized. These circuits operate at low power where no appreciable thermal cycling or ohmic heating occurs. There are no sources of chemicals in the vicinity of the fuse holder enclosures during normal conditions. Fuse holders are not mounted near rotating or reciprocating equipment and are not subject to vibration. Upstream circuit breakers are used for tagging/isolation so that the fuse holders are not subject to frequent manipulations.

Table 3.6.2-2 Electrical and Instrumentation and Controls - High Voltage Insulators - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
High Voltage Insulators	IN	Porcelain; malleable iron; aluminum; galvanized steel; cement; toughened glass; polymers silicone rubber; fiberglass, aluminum alloy	(E) Air – outdoor	Reduced electrical insulation resistance	High-Voltage Insulators (B2.1.45)	VI.A.LP-28	3.6.1-003	A
		Porcelain; malleable iron; aluminum; galvanized steel; cement; toughened glass; polymers silicone rubber; fiberglass, aluminum alloy	(E) Air – outdoor	Loss of material	High-Voltage Insulators (B2.1.45)	VI.A.LP-32	3.6.1-002	A

Table 3.6.2-2 Plant-Specific Notes: None

Table 3.6.2-3 Electrical and Instrumentation and Controls - Metal Enclosed Bus - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bus and Connection Insulation	IN	Porcelain	(E) Air – indoor controlled	Reduced electrical insulation resistance	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-26	3.6.1-013	A
			(E) Air – indoor uncontrolled	Reduced electrical insulation resistance	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-26	3.6.1-013	A
			(E) Air – outdoor	Reduced electrical insulation resistance	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-26	3.6.1-013	A
		Thermo-plastic organic polymers	(E) Air – indoor controlled	Reduced electrical insulation resistance	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-26	3.6.1-013	A
			(E) Air – indoor uncontrolled	Reduced electrical insulation resistance	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-26	3.6.1-013	A
			(E) Air – outdoor	Reduced electrical insulation resistance	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-26	3.6.1-013	A
		Xenoy®	(E) Air – indoor controlled	Reduced electrical insulation resistance	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-26	3.6.1-013	A
			(E) Air – indoor uncontrolled	Reduced electrical insulation resistance	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-26	3.6.1-013	A
Bus and Connections	CE	Various metals used for electrical bus and connections	(E) Air – indoor controlled	Increased electrical resistance of connection	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-25	3.6.1-012	A
			(E) Air – indoor uncontrolled	Increased electrical resistance of connection	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-25	3.6.1-012	A
			(E) Air – outdoor	Increased electrical resistance of connection	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-25	3.6.1-012	A

Table 3.6.2-3 Electrical and Instrumentation and Controls - Metal Enclosed Bus - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bus Enclosure	EN	Aluminum	(E) Air – indoor uncontrolled	None	None	VI.A.LP-41	3.6.1-023	A
			(E) Air – outdoor	Loss of material	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-42	3.6.1-015	A
		Elastomer	(E) Air – indoor controlled	Surface cracking, crazing, scuffing, dimensional change (e.g. "ballooning" and "necking"), shrinkage, discoloration, hardening, loss of strength	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-29	3.6.1-011	A
			(E) Air – indoor uncontrolled	Surface cracking, crazing, scuffing, dimensional change (e.g. "ballooning" and "necking"), shrinkage, discoloration, hardening, loss of strength	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-29	3.6.1-011	A
			(E) Air – outdoor	Surface cracking, crazing, scuffing, dimensional change (e.g. "ballooning" and "necking"), shrinkage, discoloration, hardening, loss of strength	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-29	3.6.1-011	A
		Steel	(E) Air – indoor controlled	None	None	VI.A.LP-44	3.6.1-024	A
			(E) Air – indoor uncontrolled	Loss of material	Metal-Enclosed Bus (B2.1.42)	VI.A.LP-43	3.6.1-014	A

Table 3.6.2-3 Plant-Specific Notes: None

Table 3.6.2-4 Electrical and Instrumentation and Controls - Electrical Equipment Subject to 10 CFR 50.49 Environmental Qualification - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Electrical Equipment Subject to 10 CFR 50.49 Environmental Qualification	CE	Various metallic materials	(E) 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 (for EQ)	Environmental Qualification of Electric Equipment (B3.3)	VI.B.L-05	3.6.1-001	A
Electrical Equipment Subject to 10 CFR 50.49 Environmental Qualification	IN	Various polymeric materials	(E) 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 (for EQ)	Environmental Qualification of Electric Equipment (B3.3)	VI.B.L-05	3.6.1-001	A

Table 3.6.2-4 Plant-Specific Notes: None

Tables 3.6.2-1 through 3.6.2-4 Industry Standard Notes:

A. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

B. Consistent with NUREG-2191 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-2191 AMP.

C. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP is consistent with NUREG-2191 AMP.

D. Component is different, but consistent with NUREG-2191 item for material, environment, and aging effect. AMP takes some exceptions to the NUREG-2191 AMP.

E. Consistent with NUREG-2191 item for 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.

G. Environment not in NUREG-2191 for this component and material.

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.

J. Neither the component nor the material and environment combination is evaluated in NUREG-2191.

4.0 TIME-LIMITED AGING ANALYSES

4.1 INTRODUCTION

Time-Limited Aging Analyses (TLAAs) are described in 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants" (Reference 1.7-2). This section provides the results of evaluations of TLAAs and any exemptions that are based on TLAAs. This section evaluates each identified TLAA in accordance with 10 CFR 54.21(c).

Section 4.1.1, Identification of Time-Limited Aging Analyses, provides the 10 CFR 54.3(a) definition of TLAAs, indicates the requirements for evaluation of TLAAs, and summarizes the process used for identifying TLAAs at North Anna Power Station (NAPS). Later sections address related TLAA issues, including Section 4.1.2, Evaluation of Time-Limited Aging Analyses; Section 4.1.3, Acceptance Criteria; Section 4.1.4, Identification of Exemptions; and Section 4.1.5, Summary of Results.

Subsequent sections of this chapter describe the evaluation of TLAAs within the following categories:

- *Reactor Vessel Neutron Embrittlement Analysis* program (Section 4.2)
- *Metal Fatigue* program (Section 4.3)
- *Environmental Qualification of Electric Equipment* program (Section 4.4)
- *Concrete Containment Tendon Prestress* program (Section 4.5)
- *Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis* program (Section 4.6)
- *Other Plant-Specific Time-Limited Aging Analyses* program (Section 4.7)
- *References for Section 4 TLAAs* program (Section 4.8)

4.1.1 IDENTIFICATION OF TIME-LIMITED AGING ANALYSES

An analysis, calculation, or evaluation is a TLAA under the 10 CFR 54 License Renewal Rule, only if it meets all six of the following 10 CFR 54.3(a) criteria:

1. Involves systems, structures, and components within the scope of license renewal, as delineated in 10 CFR 54.4(a);
2. Considers the effects of aging;
3. Involves time-limited assumptions defined by the current operating term, for example, 40 years;
4. Was determined to be relevant by the licensee in making a safety determination;
5. Involves conclusions or provides the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in 54.4(b); and
6. Is contained or incorporated by reference in the current licensing basis (CLB).

TLAAs from the initial license renewal were reviewed against the definition in 10 CFR 54.3(a) to determine whether TLAAs meet the definition of TLAA for the subsequent period of extended operation. In addition, other potential TLAAs were identified and reviewed against the definition of TLAAs in 10 CFR 54.3(a).

In accordance with 10 CFR 54.21(c)(1), a license renewal application must include a list of TLAAs, as defined in 10 CFR 54.3. 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 chapter provides the demonstration prescribed in 10 CFR 54.21(c)(1).

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" (Reference 1.7-4)
- NUREG-2192, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants" (Reference 1.7-3)
- NEI 17-01, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal" (Reference 1.7-6)
- 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants"
- Prior license renewal applications
- Plant-specific document reviews and interviews with plant personnel

Keyword searches were performed on the CLB documentation to determine whether these potential TLAAs exist in the CLB. The keyword search was also used to identify additional potential plant-specific TLAAs. The CLB search included:

- Changes to the Updated Final Safety Analysis Report (UFSAR) (Reference 1.7-18)
- Changes to the Technical Specifications and Bases (Reference 1.7-17)
- NRC Safety Evaluation Reports (SERs) for the original operating license
- Subsequent NRC Safety Evaluations (SEs)
- Docketed licensing correspondence between Virginia Electric and Power Company 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. For each TLAA from the initial license renewal there is a corresponding TLAA for the subsequent period of extended operation.

4.1.2 EVALUATION OF TIME-LIMITED AGING ANALYSES

Each TLAA has been evaluated and the description of each evaluation includes the following information:

TLAA Description:

A description of the CLB analysis that has been identified as a TLAA, including a description of the associated aging effect and the time-limited assumption used in the analysis.

TLAA Evaluation:

The evaluation of the TLAA for the subsequent period of extended operation. This section provides the information associated with 80 years of operation for comparison with the information used in the related TLAA that considered the previous license term of operation. This evaluation provides the basis for the disposition, which will be one of the three options specified in 10 CFR 54.21(c)(1).

TLAA Disposition:

Each TLAA is demonstrated acceptable in accordance with one of the three options from 10 CFR 54.21(c)(1) specified in Section 4.1.3.

4.1.3 ACCEPTANCE CRITERIA

10 CFR 54.21, Contents of application - technical information, specifies that an application must contain the following information:

(c) An evaluation of time-limited aging analyses.

1. A list of time-limited aging analyses as defined in 10 CFR 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.

One of these three methods was used to disposition each TLAA identified. The methods used are identified in each TLAA evaluation section.

4.1.4 IDENTIFICATION OF EXEMPTIONS

10 CFR 54.21(c)(2) requires a list 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.

Docketed licensing correspondence, the operating license, and the UFSAR were searched to identify exemptions in effect. Each exemption in effect was then evaluated to determine whether it was based on a TLAA as defined in 10 CFR 54.3.

There were no exemptions to 10 CFR 50.12 identified that are currently in effect that are based upon a TLAA.

4.1.5 SUMMARY OF RESULTS

Table 4.1.5-1, Review of Generic TLAAs Listed in NUREG-2192, Table 4.1-2 and Table 4.7-1, lists the example TLAAs provided in NUREG-2192 and specifies whether they have been identified as TLAAs. 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 Section 4.7 of this chapter describe the evaluations of six general categories of TLAAs. The TLAA categories and associated analysis are listed in Table 4.1.5-2, Time-Limited Aging Analyses Categories and Dispositions. The TLAA categories are presented in the order in which they appear in Sections 4.2 through Section 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 subsequent license renewal application (SLRA) section where the TLAA is evaluated for the subsequent period of extended operation.

Table 4.1.5-1 Review of Generic TLAAs Listed in NUREG-2192, Table 4.1-2 and Table 4.7-1

NUREG-2192, Table 4.1-2 - Generic TLAAs	Applies to NAPS	SLRA Section
Neutron Fluence	Yes	Section 4.2.1
Pressurized Thermal Shock (PWRs Only)	Yes	Section 4.2.3
Upper Shelf Energy (PWRs and BWRs)	Yes	Section 4.2.2
Pressure Temperature (P-T) Limits (PWRs and BWRs)	Yes	Section 4.2.4 Section 4.2.5
Low Temperature Overpressure Protection System Setpoints (PWRs Only)	Yes	Section 4.2.6
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 of Class 1 Components	Yes	Section 4.3.2
Metal Fatigue of Non-Class 1 Components	Yes	Section 4.3.3
Environmentally-Assisted Fatigue	Yes	Section 4.3.4
High-Energy Line Break Analyses	Yes	Section 4.3.6
Cycle-dependent Fracture Mechanics or Flaw Evaluations	Yes	Section 4.3.4
Cycle-dependent Fatigue Waivers	Yes	Section 4.3.2.9
Environmental Qualification of Electric Equipment	Yes	Section 4.4
Concrete Containment Tendon Prestress	No	Section 4.5
Containment Liner Plate, Metal Containments, and Penetrations Fatigue	Yes	Section 4.6

Table 4.1.5-1 Review of Generic TLAAs Listed in NUREG-2192, Table 4.1-2 and Table 4.7-1

NUREG-2192, Table 4.7-1 - Examples of Potential Plant Specific TLAA Topics	Applies to NAPS	SLRA Section
Reactor Pressure Vessel Underclad Cracking	Yes	Section 4.7.7
Leak-Before-Break	Yes	Section 4.7.3
Reactor Coolant Pump Flywheel Fatigue Crack Growth	Yes	Section 4.7.2
Response to NRC Bulletin 88-11, “Pressurizer Surge Line Thermal Stratification”	Yes	Section 4.3.2.6
Response to NRC Bulletin 88-08, “Thermal Stresses in Piping Connected to Reactor Cooling Systems”	No[(a)]	N/A
Fatigue of Cranes (Crane Cycle Limits)	Yes	Section 4.7.1
Fatigue of the Spent Fuel Pool Liner	Yes	Section 4.7.4
Corrosion Allowance Calculations	No	N/A
Flaw Growth Due to Stress Corrosion Cracking	No	N/A
Predicted Lower Limit	No	N/A

NOTE:

(a) No ASME Code, Section III cumulative usage factor (CUF) analyses were generated in response to NRC IE Bulletin 88-08. Ultrasonic inspections were performed in response to IEB 88-08.

Table 4.1.5-2 Time-Limited Aging Analyses Categories and Dispositions

TLAA CATEGORY	ANALYSIS	DISPOSITION (Note 1)	SECTION
REACTOR VESSEL NEUTRON EMBRITTLEMENT ANALYSIS	Neutron Fluence Projections	(ii)	Section 4.2.1
	Upper-Shelf Energy	(ii)	Section 4.2.2
	Pressurized Thermal Shock	(ii)	Section 4.2.3
	Adjusted Reference Temperature	(ii)	Section 4.2.4
	Pressure-Temperature Limits	(iii)	Section 4.2.5
	Low Temperature Overpressure Protection	(ii)	Section 4.2.6
METAL FATIGUE	Transient Cycle Projections for 80 years	Not Applicable	Section 4.3.1
	ASME Code, Section III, Class 1 Fatigue Analyses	See Section 4.3.2 Subsections	Section 4.3.2
	Control Rod Drive Mechanism	(iii)	Section 4.3.2.1
	Pressurizer	(iii)	Section 4.3.2.2
	Reactor Coolant Pump	(iii)	Section 4.3.2.3
	Reactor Vessel	(iii)	Section 4.3.2.4
	Steam Generators	(iii)	Section 4.3.2.5
	Pressurizer Surge Line	(iii)	Section 4.3.2.6
	Class 1 USAS (ANSI) B31.7 Piping	(i)	Section 4.3.2.7
	Loop Stop Isolation Valves	(iii)	Section 4.3.2.8
	ASME Code, Section III, Class I Component Fatigue Waivers	(iii)	Section 4.3.2.9
	USAS (ANSI) B31.1 Allowable Stress Analyses	(i)	Section 4.3.3
	Environmentally-Assisted Fatigue	(iii)	Section 4.3.4
	Reactor Vessel Internals Fatigue Analyses	(i)	Section 4.3.5
	High-Energy Line Break Analysis	(i)	Section 4.3.6

Table 4.1.5-2 Time-Limited Aging Analyses Categories and Dispositions

TLAA CATEGORY	ANALYSIS	DISPOSITION (Note 1)	SECTION
ENVIRONMENTAL QUALIFICATION OF ELECTRIC EQUIPMENT		(iii)	Section 4.4
CONCRETE CONTAINMENT TENDON PRESTRESS	Concrete Containment Tendon Prestress	Not Applicable	Section 4.5
CONTAINMENT LINER PLATE, METAL CONTAINMENTS & PENETRATIONS FATIGUE ANALYSES	Containment Liner Plate	(ii)	Section 4.6.1
	Metal Containment	N/A	Section 4.6.2
	Containment Penetrations Fatigue Analyses	Not a TLAA	Section 4.6.3
OTHER PLANT-SPECIFIC TLAAs	Crane Load Cycle Limits	(i)	Section 4.7.1
	Reactor Coolant Pump Flywheel Fatigue Crack Growth Analyses	(i)	Section 4.7.2
	Leak-Before-Break	(ii)	Section 4.7.3
	Spent Fuel Pool Liner Fatigue Analyses	(ii)	Section 4.7.4
	Piping Subsurface Flaw Evaluations	(ii)	Section 4.7.5
	Reactor Coolant Pump Code Case N-481	(i)	Section 4.7.6
	Cracking Associated with Weld Deposited Cladding	(ii)	Section 4.7.7
	Steam Generator Tube Wear Evaluation	(iii)	Section 4.7.8

Note 1:

(i) Validation: The analyses remain valid for the subsequent period of extended operation.

(ii) Projection: The analyses have been projected to the end of the subsequent period of extended operation.

(iii) Aging Management: The effects of aging on the intended function(s) will be adequately managed for the subsequent period of extended operation.

4.2 REACTOR VESSEL NEUTRON EMBRITTLEMENT ANALYSIS

10 CFR 50.60, “Acceptance Criteria for Fracture Prevention Measures for Lightwater Nuclear Reactors for Normal Operation,” 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 materials included in the surveillance capsule program remain unchanged for the subsequent period of extended operation based upon the provisions outlined in ASTM E185-73, “Standard Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels” (Reference 4.8-1) that existed at the time of initial plant construction. 10 CFR 50.61 requires that all light water reactors meet the fracture toughness requirements for protection against pressurized thermal shock events. The Reactor Vessel Material Surveillance program is described in Section B2.1.19.

Inputs for reactor vessel (RV) integrity assessments are discussed in this section.

The best estimate copper (Cu) and nickel (Ni) chemical compositions for the Units 1 and 2 RV materials are presented in Table 4.2.2-1 and Table 4.2.2-2, respectively. The best estimate weight %Cu and Ni values for the RV materials were reported in PWROG-18005-NP, “Determination of Unirradiated RT_{NDT} and Upper-Shelf Energy Values of the North Anna Units 1 and 2 Reactor Vessel Materials” (Reference 4.8-2) and were included in RV integrity evaluations as part of this TLAA effort.

Prior to updating the RV integrity assessments for the subsequent period of extended operation both the fluence projections and material properties were reviewed and updated by WCAP-18015-NP, Revision 2, “Extended Beltline Pressure Vessel Fluence Evaluations Applicable to North Anna Units 1 & 2" (Reference 4.8-3), and PWROG-18005-NP. Revised initial material properties, including chemistry factors and fluence projections, through 72 EFPY are included in Table 4.2.3-1 and Table 4.2.3-2 for Units 1 and 2 respectively.

The neutron fluence axial boundary of the 1.0 x 10^{17} n/cm^2, fluence threshold is depicted in Table 4.2.2-1 and Table 4.2.2-2 for Units 1 and 2 respectively. The configuration of the RVs is illustrated in Figure 4.2.2-3 for Units 1 and 2. There are no longitudinal welds on the Units 1 and 2 RVs.

Reactor vessel integrity assessments are performed for both the beltline region (identified in 10 CFR 50, Appendix G) and extended beltline region (fluence values >1.0 x 10^{17} n/cm^2, E >1 MeV).

The beltline region is the region of the RV (shell material, including welds, heat-affected zones, and plate or forgings) that directly surrounds the effective height of the active core and the adjacent regions of the RV that are predicted to experience sufficient neutron irradiation damage to be considered in the selection of the most limiting material with regard to radiation damage during the licensed period.

The extended beltline means the region of the RV (shell material, including welds, heat-affected zones, and plate or forgings) adjacent to the beltline region that will have associated fluence values projected to exceed 1.0×10^{17} n/cm^2 during the subsequent period of extended operation.

The ferritic materials of the RV 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 crack propagation or rupture), thus allowing a crack to propagate more easily under thermal and pressure loading. Neutron embrittlement analyses account for the reduction in fracture toughness associated with the cumulative neutron fluence. Because these neutron embrittlement analyses use a fluence assumption based on the plant's current operating term, they are identified as time-limited aging analyses.

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 the USE decrease of RV steels. This means that RV materials may no longer behave in a ductile manner at postulated plant operating temperatures. For beltline materials the limit for initial USE is 75 ft-lbs. The limit for reduced USE of beltline materials following irradiation is 50 ft-lbs. The material outside the beltline was originally qualified using the requirements of the codes in effect at the time of the initial design and fabrication of the RVs for Units 1 and 2, which were a minimum Charpy impact energy value of 30 ft-lbs at 10°F as specified by ASTM E208, “Standard Test Method for Conducting Drop-Weight Test to Determine Nil-Ductility Transition Temperature of Ferritic Steels” (Reference 4.8-4) and required by ASME Code, Section III, “Rules for Construction of Nuclear Facility Components” (Reference 4.8-5).

To reduce the potential for brittle fracture during RV operation, changes in material toughness as a function of neutron radiation exposure (fluence) are accounted for during development of operating pressure temperature (P-T) limits that are included in the Technical Specifications. The P-T limits account for the decrease in material toughness of RV materials during plant operation. Since the cumulative neutron fluence will increase during the subsequent period of extended operation, a review is needed to determine if additional components require evaluation for neutron embrittlement.

10 CFR 50.61 requirements for pressurized thermal shock events specify screening criteria of 270°F for plates, forgings, and axial welds and 300°F for circumferential welds. The RT_{PTS} values have been projected through the subsequent period of extended operation.

USE and RT_{PTS} calculations are performed for each beltline and extended beltline material to determine if the components will continue to have adequate fracture toughness with the reduction in toughness resulting from exposure to the predicted neutron fluence. While the decrease in USE for materials in the extended beltline approaches (but remains greater than or equal to) 50 ft-lbs, as a conservative measure, an equivalent margins analysis has been performed for the inlet and outlet nozzle welds.

P-T limit curves are generated to provide minimum temperature limits that must be satisfied during operations. 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 enabling temperature and LTOP setpoint are validated as they are impacted by fluence.

The RV material evaluations, calculated on the basis of neutron fluence, are part of the current licensing basis and support safety determinations. Therefore, these calculations have been identified as TLAAs.

The evaluations of TLAAs related to neutron embrittlement are described in the following subsections:

- Neutron Fluence Projections (Section 4.2.1)
- Upper-Shelf Energy (Section 4.2.2)
- Pressurized Thermal Shock (Section 4.2.3)
- Adjusted Reference Temperature (Section 4.2.4)
- Pressure-Temperature Limits (Section 4.2.5)
- Low Temperature Overpressure Protection Analyses (Section 4.2.6)

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 RV shell. The fluence projections that quantify the number of neutrons that contact these surfaces have been used as inputs to the neutron embrittlement analyses that evaluate the reduction of fracture toughness aging effect resulting from neutron irradiation and will be treated as a TLAA.

TLAA Evaluation:

Per NUREG-1766, “Safety Evaluation Report Related to the License Renewal of North Anna Power Station, Units 1 and 2, and North Anna Power Station, Units 1 and 2" (Reference 4.8-6), RV beltline neutron fluence values applicable to the 60-year period of operation were calculated using the NRC approved VEP-NAF-3-A, “Virginia Power Reactor Vessel Fluence Methodology Topical Report” (Reference 4.8-7). The methodology described in that report was developed in accordance with Draft Regulatory Guide DG-1053, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence” (Reference 4.8-8).

Those projections were superseded in WCAP-18015-NP, Revision 0, “Extended Beltline Pressure Vessel Fluence Evaluations Applicable to North Anna 1 & 2,” (Reference 4.8-9) as part of an update to the P-T Limit Curves in 2015.

EFPY Projections

EFPY values for Unit 1 and 2 are as follows:

Unit 1	34.4 EFPY, as of September 8, 2019
Unit 2	33.2 EFPY, as of March 3, 2019

The first step in updating fluence projections for 80 years is to estimate the power history based upon actual unit operating history and a conservative capacity factor estimate for future cycles. Units 1 and 2 are licensed for 60 years of operation; therefore, with a 20-year license renewal, the subsequent license renewal term is 80 years.

The EFPY projections through the end of the subsequent period of extended operation for a unit is the sum of the accumulated EFPY and the projected future EFPY. EFPY at the end of 60 years of operation was calculated to be 50.3 EFPY for Unit 1 and 52.3 EFPY for Unit 2. An estimate of the EFPY at the end of 80 years of operation can be made conservatively assuming the 100% capacity factor for the 20-year subsequent period of extended operation. Using this conservative approach, the projected 80-year EFPY for both Units 1 and 2 is identified as 72 EFPY (actual capacity factor will be less than 100% factoring in refueling outages).

Fluence Projections

Reactor vessel integrity is assured by demonstrating that RV material fracture toughness will remain at levels that resist brittle fracture throughout the subsequent period of extended operation. The first step in the analysis of vessel embrittlement is calculation of the neutron fluence that causes increased embrittlement.

Fluence is projected for both beltline and extended beltline materials. The fluence methodology for beltline materials is approved by the NRC SE included in WCAP-14040-A, Revision 4, “Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves” (Reference 4.8-10). NUREG-2191, X.M2, indicates the use of Regulatory Guide 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence,” (Reference 4.8-11) adherent methods to estimate neutron fluence for RV regions significantly above and below the active fuel region of the core and RVI components may require additional justification. Figure 4.2.2-1 and Figure 4.2.2-2 depict the axial boundary of the 1.0 x 10^{17} n/cm^2 fluence in the Z direction. The Xs are the lowest extent of the inlet and outlet nozzles. The dots are the 1/4T postulated flaw. The nozzle shell to intermediate shell circumferential weld is located close to the active fuel region and has historically been treated as beltline material. The lower extent of the nozzle shell forging, connected to the nozzle shell to intermediate shell circumferential weld, is also beltline material. Fluence projections for these two materials satisfy Regulatory Guide 1.190. The inlet and outlet nozzles are located above the active fuel region. Some of the inlet and outlet nozzles are projected to experience neutron fluence in excess of 1.0 x 10^{17} n/cm^2. These inlet and outlet nozzles are treated as extended beltline material for subsequent license renewal.

While the fluence projections for the inlet and outlet nozzles may have greater uncertainty than other beltline materials, these fluence projections are acceptable for performing RV integrity assessments for the subsequent period of extended operation. The basis for this determination is consistent with LTR-SDA-19-099, "Evaluation of Conservatisms and Margins Associated with North Anna Units 1 and 2 Reactor Vessel Integrity Extended Beltline Evaluations for Subsequent License Renewal" (Reference 4.8-12), and is summarized as follows:

- The limiting Units 1 and 2 reactor vessel extended beltline materials have ART values that are less than the limiting beltline material ART values used for P-T limit curve development at 72 EFPY. The fluence in the extended beltline region would need to more than double in order for an extended beltline material to be limiting.
- PWROG-15109-NP-A, "PWR Pressure Vessel Nozzle Appendix G Evaluation," (Reference 4.8-13), has shown generically that the nozzles will not be limiting with respect to the 10 CFR 50, Appendix G, P-T limit curves as long as the fluence at the nozzle corner remains less than 4.28 x 10^{17} n/cm^2. Currently, the 72 EFPY fluence projection in this region is 1.48 x 10^{17} n/cm^2 at a maximum. The nozzle 1/4T flaw fluence value could increase by almost 3 times its current value before exceeding the generic evaluation's screening criterion.
- 60°F margin exists between the Units 1 and 2 limiting extended beltline RT_{PTS}value and the limiting beltline material RT_{PTS} value for Units 1 and 2. An additional margin of greater than 40°F exists (greater than 100°F total) to the RT_{PTS} screening criteria. While not applicable to the nozzles, a fluence increase greater than 3 times would be required for an extended beltline material to become limiting in terms of RT_{PTS} compared to the beltline materials.
- The projected fluence values of the Units 1 and 2 inlet/outlet nozzles could increase by 60% before exceeding the fluence value utilized in the EMA for the subsequent period of extended operation.
- The projected fluence values of the Units 1 and 2 inlet and outlet nozzle to shell welds could increase by 3 times its current value before dropping below 50 ft-lbs and exceeding the fluence value utilized in the EMA for the subsequent period of extended operation.

Updated neutron fluence evaluations were performed and documented in WCAP-18015-NP. The fluence methodology used in WCAP-18015-NP is based on nuclear cross-section data derived from Evaluated Nuclear Data File/B Version VI (ENDF/B-VI). Furthermore, the neutron transport evaluation methodologies follow the guidance of Regulatory Guide 1.190. The methods used to develop the calculated pressure vessel fluence are consistent with the NRC-approved methodology described in WCAP-14040-A. The final safety evaluation report for WCAP-14040, Revision 3, dated February 27, 2004, states that the proposed fluence methodology adheres to the guidance of Regulatory Guide 1.190 and is therefore acceptable.

Consistent with Sections 3.1 and 4.2 of NUREG-2192, materials exceeding a fast neutron fluence (E > 1.0 MeV) of 1.0 x 10^{17} n/cm^2 at the end of the subsequent period of extended operation are evaluated for changes in fracture toughness. Therefore, fast neutron (E > 1.0 MeV) fluence calculations were performed for the Units 1 and 2 RV circumferential welds (lower shell to lower vessel head, intermediate shell to lower shell, and upper shell to intermediate shell), centerline of the inlet and outlet nozzle forging to vessel shell welds at the lowest extent, postulated 1/4T flaw location in the inlet and outlet nozzle, and forgings (lower shell, intermediate shell, and upper shell), to determine if they will exceed a fast neutron fluence (E > 1.0 MeV) of 1.0 x 10^{17} n/cm^2 at the end of the subsequent period of extended operation. The materials that exceed the 1.0 x 10^{17} n/cm^2 fast neutron fluence (E > 1.0 MeV) threshold are evaluated to determine the effect of neutron irradiation embrittlement during the subsequent period of extended operation.

Table 4.2.1-1 and Table 4.2.1-2 summarize the results of the fluence projections to 72 EFPY for the Units 1 and 2 materials.

Table 4.2.1-1 indicates that one outlet nozzle and two inlet nozzles have fast neutron (E > 1.0 MeV) fluence greater than 1.0 x 10^{17} n/cm^2 at the nozzle forging to vessel shell weld centerline and one inlet nozzle has a fast neutron (E > 1.0 MeV) fluence greater than 1.0 x 10^{17} n/cm^2 at the postulated 1/4T nozzle flaw location at 72 EFPY for Unit 1. Table 4.2.1-2, indicates one outlet nozzle and two inlet nozzles have fast neutron (E > 1.0 MeV) fluence greater than 1.0 x 10^{17} n/cm^2 at the nozzle forging to vessel shell weld centerline and one inlet nozzle has a fast neutron (E > 1.0 MeV) fluence greater than 1.0 x 10^{17} n/cm^2 at the postulated 1/4T nozzle flaw location at 72 EFPY for Unit 2. Table 4.2.1-1 and Table 4.2.1-2 indicate that the lower shell to lower vessel head circumferential weld will remain below 1.0 x 10^{17} n/cm^2 through the subsequent period of extended operation for both Units 1 and 2.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The fluence analyses have been projected to the end of the subsequent period of extended operation. The results are to be used as inputs in the RV neutron embrittlement TLAA evaluations in Sections 4.2.2 through 4.2.6.

Table 4.2.1-1 Unit 1 - Maximum Fast Neutron Fluence (E > 1.0 MeV) Experienced by the Pressure Vessel Materials in the Traditional Beltline and Extended Beltline Regions at 72 EFPY

Material	Fast Neutron Fluence (n/cm^2)	
	72 EFPY[(a)]	Region Applicability
Postulated 1/4T Flaw in Inlet Nozzle		
Nozzle 09 (Ht. # 990290-11)	4.25E+16	Extended Beltline[(h)]
Nozzle 10[(b)] (Ht. # 990290-12)	1.48E+17	Extended Beltline
Nozzle 11 (Ht. # 990268-11)	5.68E+16	Extended Beltline[(h)]
Postulated 1/4T Flaw in Outlet Nozzle		
Nozzle 12 (Ht. # 990290-31)	8.75E+16	Extended Beltline[(h)]
Nozzle 13 (Ht. # 990290-22)	2.51E+16	Extended Beltline[(h)]
Nozzle 14 (Ht. # 990290-21)	3.35E+16	Extended Beltline[(h)]
Centerline of the Inlet Nozzle Forging to Vessel Shell Welds – Lowest Extent[(i)]		
Nozzle 09	8.98E+16	Extended Beltline[(h)]
Nozzle 10[(d)]	3.13E+17	Extended Beltline
Nozzle 11[(e)]	1.20E+17	Extended Beltline
Centerline of the Outlet Nozzle Forging to Vessel Shell Welds – Lowest Extent[(i)]		
Nozzle 12[(c)]	1.82E+17	Extended Beltline
Nozzle 13	5.22E+16	Extended Beltline[(h)]
Nozzle 14	6.97E+16	Extended Beltline[(h)]
Upper Shell (Ht. # 990286 / 295213)	3.04E+18	Beltline
Upper Shell to Intermediate Shell Circumferential Weld (Ht. # 25295 & 4278)	3.51E+18	Beltline
Intermediate Shell (Ht. # 990311 / 298244)	7.07E+19	Beltline
Intermediate Shell to Lower Shell Circumferential Weld (Ht. # 25531)	7.04E+19	Beltline
Lower Shell (Ht. # 990400 / 292332)	7.20E+19	Beltline
Lower Shell to Lower Vessel Head Circumferential Weld[(g)(i)]	<1.00E+17	Outside Beltline

Notes:

(a) Corresponds to 80 years of life.

(b) 1/4T Flaw in Inlet Nozzle Inlet 10 is projected to reach 1.0E+17 n/cm^2 at approximately 48.5 EFPY; which corresponds to December 26, 2034[(f)].

(c) Outlet Nozzle 12 is projected to reach 1.0E+17 n/cm^2 at approximately 39.5 EFPY; which corresponds to June 6, 2025[(f)].

(d) Inlet Nozzle 10 reached 1.0E+17 n/cm^2 at approximately 22.4 EFPY, which occurred during Cycle 19.

(e) Inlet Nozzle 11 is projected to reach 1.0E+17 n/cm^2 at approximately 60.3 EFPY; which corresponds to May 1, 2047[(f)].

(f) Note, the dates provided in notes b, c, and e are approximations based on an 18-month cycle and average outage time of 25 days.

(g) The lower shell to lower vessel head circumferential weld is not modeled, it is known to be below the 1.0E+17 n/cm^2 fast neutron fluence threshold due to the fact that: it is 32 cm further from the core midplane than the above-core threshold location at 72 EFPY, and that the coolant below the core is cooler than the coolant above the core, which increases the density and shielding effects, reducing the fluence below the core relative to above the core.

(h) Component is conservatively included in the “Extended Beltline” even though its projected SLR fluence is less than 1.0E+17 n/cm^2 (E > 1.0 MeV) because, either a component at the same axial elevation meets the “Extended Beltline” fluence criterion, or the same component meets the fluence criterion at a lower elevation.

(i) The specific heat numbers of these welds could not be identified in the available information.

Table 4.2.1-2 Unit 2 - Maximum Fast Neutron Fluence (E > 1.0 MeV) Experienced by the Pressure Vessel Materials in the Beltline and Extended Beltline Regions at 72 EFPY

Material	Fast Neutron Fluence (n/cm^2)	
	72 EFPY[(a)]	Region Applicability
Postulated 1/4T Flaw in Inlet Nozzle		
Nozzle 09 (Ht. # 990426)	3.90E+16	Extended Beltline[(h)]
Nozzle 10[(b)] (Ht. #54567-2)	4.28E+17	Extended Beltline
Nozzle 11 (Ht. #54590-2)	5.59E+16	Extended Beltline[(h)]
Postulated 1/4T Flaw in Outlet Nozzle		
Nozzle 12 (Ht. #990426-22)	8.75E+16	Extended Beltline[(h)]
Nozzle 13 (Ht. #990426-31)	2.30E+16	Extended Beltline[(h)]
Nozzle 14 (Ht. #791291)	3.30E+16	Extended Beltline[(h)]
Centerline of the Inlet Nozzle Forging to Vessel Shell Welds – Lowest Extent (Ht. # 8816, 20459, & 27622)		
Nozzle 09	8.26E+16	Extended Beltline[(h)]
Nozzle 10[(d)]	3.14E+17	Extended Beltline
Nozzle 11[(e)]	1.18E+17	Extended Beltline
Centerline of the Outlet Nozzle Forging to Vessel Shell Welds – Lowest Extent (Ht. # 8816,20459, & 27622)		
Nozzle 12[(c)]	1.82E+17	Extended Beltline
Nozzle 13	4.79E+16	Extended Beltline[(h)]
Nozzle 14	6.87E+16	Extended Beltline[(h)]
Upper Shell (Ht. # 990598 / 291396)	3.07E+18	Beltline
Upper Shell to Intermediate Shell Circumferential Weld (Ht. # 4278 & 801)	3.55E+18	Beltline
Intermediate Shell (Ht. # 990496 / 292424)	7.20E+19	Beltline
Intermediate Shell to Lower Shell Circumferential Weld (Ht. # 716126)	7.18E+19	Beltline
Lower Shell (Ht. # 990533 / 297355)	7.34E+19	Beltline
Lower Shell to Lower Vessel Head Circumferential Weld[(g)] (Ht. # 716126)	<1.00E +17	Outside Beltline

Notes:

(a) Corresponds to 80 years of life.

(b) Postulated 1/4T Flaw in Inlet Nozzle Inlet 10 is projected to reach 1.0E+17 n/cm^2 at approximately 48.8 EFPY; which corresponds to May 27, 2036[f].

(c) Outlet Nozzle 12 is projected to reach 1.0E+17 n/cm^2 at approximately 39.8 EFPY; which corresponds to February 4, 2027[f].

(d) Inlet Nozzle 10 reached 1.0E+17 n/cm^2 at approximately 23.1 EFPY, which occurred during Cycle 20.

(e) Inlet Nozzle 11 is projected to reach 1.0E+17 n/cm^2 at approximately 60.9 EFPY; which corresponds to February 12, 2049[f].

(f) Note, the dates provided in notes b, c, and e are approximations based on an 18-month cycle and average outage time of 25 days.

(g) The lower shell to lower vessel head circumferential weld is not modeled, it is known to be below the 1E+17 n/cm^2 fast neutron fluence threshold due to the fact that: it is 32 cm further from the core midplane than the above-core threshold location at 72 EFPY, and that the coolant below the core is cooler than the coolant above the core, which increases the density and shielding effects, reducing the fluence below the core relative to above the core.

(h) Component is conservatively included in the “Extended Beltline” even though its projected SLR fluence is less than 1E+17 n/cm^2 (E > 1.0 MeV) because, either a component at the same axial elevation meets the “Extended Beltline” fluence criterion, or the same component meets the fluence criterion at a lower elevation.

4.2.2 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 RV beltline materials must have Charpy USE of no less than 75 ft-lbs initially, and must maintain Charpy USE throughout the life of the vessel of no less than 50 ft-lbs, 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 ASME Code, Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components,” (Reference 4.8-14) Appendix G, “Fracture Toughness Criteria for Protection Against Failure.” For materials outside the beltline, a minimum value of 30 ft-lbs at 10°F was specified by ASTM E208, and required by ASME Code, Section III, at the time of the design and fabrication of the RVs for Units 1 and 2.

The current licensing basis Charpy USE calculations were prepared for the Units 1 and 2 RV beltline materials for 50.3 EFPY for Unit 1, and 52.3 EFPY for Unit 2. Since the USE value is a function of EFPY fluence, associated with the 60-year licensed operating period, these USE calculations meet the criteria of 10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for 80 years.

TLAA Evaluation:

Per Regulatory Guide 1.99, “Radiation Embrittlement of Reactor Vessel Materials,” (Reference 4.8-15) the Charpy USE should be assumed to decrease as a function of fluence according to Figure 2 of the Regulatory Guide, which provides % decrease in USE as a function of 1/4T fluence and the copper content for plates and welds, when credible surveillance data is not available. If credible surveillance data is available, the decrease in USE may be obtained by plotting the reduced plant surveillance data on Figure 2 of Regulatory Guide 1.99 and fitting the data with a line drawn parallel to the existing lines as the upper bound of all of the data. The 1/4T fluence at 72 EFPY is used to determine the reduction in the initial USE.

As documented in WCAP-18364-NP, “North Anna Units 1 and 2 Time-Limited Aging Analysis on Reactor Vessel Integrity for Subsequent License Renewal (SLR)” (Reference 4.8-16), the materials projected to exceed 1.0 x 10^{17} n/cm^2 (E > 1.0 MeV) at 72 EFPY are evaluated to determine their impact on USE during the proposed subsequent period of extended operation. The forgings and welds corresponding to some inlet and outlet nozzles are predicted to experience neutron fluence greater than 1.0 x 10^{17} n/cm^2 at the end of the subsequent period of extended operation. However, for conservatism, all of the inlet and outlet nozzle materials are considered part of the extended beltline in the USE evaluation. The Units 1 and 2 materials include three (3) inlet nozzles, three (3) outlet nozzles, three (3) inlet nozzle to upper-shell welds, and three (3) outlet nozzle to upper-shell welds per unit. (Note: nozzle-shell and upper-shell refer to the same component and are used interchangeably.)

The identification of the RV plate and weld materials is shown in Table 4.2.2-1 for Unit 1 and Table 4.2.2-2 for Unit 2. The material property inputs used for the RV integrity evaluations are described in this section. The initial material properties were updated from previous RV integrity evaluations per PWROG-18005-NP and WCAP-18364-NP, and the fluence values were updated per WCAP-18015-NP and WCAP-18364-NP. Additionally, initial USE values are supplied in Table 4.2.2-1 and Table 4.2.2-2.

The requirements on USE for beltline materials are included in 10 CFR 50, Appendix G, which requires utilities to submit an analysis at least three years prior to the time that the USE of any RV material is predicted to drop below 50 ft-lbs.

Two methods 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, Revision 2. For vessel 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 Regulatory Guide 1.99, Revision 2. When two or more credible surveillance sets become available from the reactor, they may be used to determine the Charpy USE of the surveillance material. The surveillance data are then used in conjunction with Regulatory Guide 1.99, Revision 2, to predict the change in USE (Position 2.2) of the RV material due to irradiation. Per Regulatory Guide 1.99, Revision 2, when credible data exists 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 vessel materials can be predicted using the corresponding fluence projections (1/4T for beltline materials and surface for inlet/outlet nozzles), the copper content of the materials, and Figure 2 in Regulatory Guide 1.99, Revision 2.

The predicted Position 2.2 USE values are determined for the RV materials that are contained in the surveillance program by using the reduced plant surveillance data along with the corresponding fluence projection (1/4T for beltline materials and surface for inlet/outlet nozzles). The reduced plant surveillance data was obtained from Table 7-6 of BAW-2356, “Analysis of Capsule W Virginia Power North Anna Unit No. 1 Nuclear Power Plant, Reactor Vessel Material Surveillance Program” (Reference 4.8-17) for Unit 1. The reduced plant surveillance data was obtained from Table 7-6 of BAW-2376, “Analysis of Capsule W, Virginia Power North Anna Unit No. 2 Nuclear Power Plant, Reactor Vessel Material Surveillance Program” (Reference 4.8-18) for Unit 2. The surveillance data was plotted in Regulatory Guide 1.99, Revision 2, Figure 2 using the surveillance capsule fluence values documented in Table 2-1 of WCAP-18364-NP, for Unit 1 and Table 2-2 of WCAP-18364-NP, for Unit 2.

The projected USE values were calculated to determine if the values for Units 1 and 2 materials remain above the 50 ft-lbs criterion at 72 EFPY. The projected USE values for the inlet and outlet nozzle forgings were conservatively calculated using the maximum fluence values corresponding to the lowest extent of the nozzle to shell welds. These calculations are summarized in Table 4.2.2-3 and Table 4.2.2-4.

Conclusion

For Unit 1, the limiting USE value at 72 EFPY is 50.0 ft-lbs; this value corresponds to Inlet Nozzle Forging 11 using Position 1.2. The Unit 1 Inlet Nozzle 11 USE value set equal to 50 ft-lbs results in a projected drop of 10.7%. Fluence values for nozzles were determined at the surface and is not attenuated. A review of Regulatory Guide 1.99, Revision 2, Figure 2 resulted in a conservative estimate of approximately 11%, but the figure has limited precision. A decrease of 10.7% is considered appropriate based on the following conservatism in the calculations. The estimated percent decrease is based on a fluence of 2 x 10^{17} n/cm^2 (E > 1.0 MeV), which is the lowest fluence line displayed in Regulatory Guide 1.99, Revision 2, Figure 2. The actual fluence is projected to be roughly half this (i.e., 1.20 x 10^{17} n/cm^2 (E > 1.0 MeV)), at the lowest extent of the nozzle weld and fluence would be even lower at higher axial elevations. In addition, the fluence would be further decreased if attenuation to the 1/4T location were considered. These additional decreases in fluence would raise the projected USE of Unit 1 Inlet Nozzle 11 above 50 ft-lbs. As shown in Table 4.2.2-3, all Unit 1 reactor vessel materials are projected to remain at or above the USE screening criterion value of 50 ft-lbs at 72 EFPY.

For Unit 2, the limiting USE value at 72 EFPY is 48.2 ft-lbs; this value corresponds to the Intermediate Shell Forging 04 using Position 2.2. Position 2.2 was used to determine the Unit 2 Intermediate Shell Forging 04 USE value even though its surveillance data was deemed non-credible per Appendix A of WCAP-18364-NP. Per Regulatory Guide 1.99, Revision 2, this is appropriate since the upper shelf can be clearly determined from the surveillance test results. As shown in Table 4.2.2-4, all other Unit 2 reactor vessel materials are projected to remain above the USE screening criterion value of 50 ft-lbs at 72 EFPY.

The Unit 2 Intermediate Shell Forging 04 reactor vessel material, which is projected to drop below 50 ft-lbs USE prior to 72 EFPY, is addressed in the equivalent margins analysis (EMA) performed in PWROG-19047-P, "North Anna Reactor Vessel Low Upper-Shelf Fracture Toughness Equivalent Margin Analysis," (Reference 4.8-19) to qualify the material at 72 EFPY per 10 CFR 50, Appendix G. The material-specific EMA must be submitted to the NRC for review and approval at least three years prior to the USE dropping below 50 ft-lbs. The Unit 2 Intermediate Shell Forging 04 is projected to drop below 50 ft-lbs at 52.3 EFPY, which is projected to occur in 2040. In addition to the material discussed above, for conservatism, PWROG-19047-P includes EMAs for all the following materials at each unit.

- Upper Shell Forging
- Intermediate Shell Forging
- Inlet Nozzle Forgings
- Outlet Nozzle Forgings
- Inlet Nozzle Welds
- Outlet Nozzle Welds

PWROG-19047-P was transmitted to the NRC through the PWROG under Letter OG-20-167, dated May 27, 2020

The EMA for the Rotterdam welds utilized the B&WOG J-integral resistance (J-R) Model 6B reported in BAW-2192, Revision 0, Supplement 1P-A, Revision 0, Appendix A. Justification for use of B&WOG Model 6B for Rotterdam welds is addressed in BAW-2192, Supplement 2P, Revision 0. The EMA for the nozzle and upper shell forgings, used J-R model per NUREG/CR-5729 Charpy model. The low upper-shelf toughness EMA is based on the projected RV neutron fluence at 80 years of operation at the RV inlet and outlet nozzle regions, which are projected to exceed 1.0×10^{17} n/cm^2 (E > 1.0 MeV) and qualified as extended beltline materials.

Units 1 and 2 RV nozzle-to-shell welds, nozzle forgings and upper shell forgings were evaluated for equivalent margins of safety per ASME Code, Section XI. The flaw extension and stability criteria of ASME Code, Section XI, Appendix K are satisfied.

Levels A/B

For all evaluated locations, the $J_{applied}$ at 0.1-inch flaw extension with a structural factor (SF) of 1.15 for pressure and SF of 1.0 for thermal are below the J-material at 0.1-inch flaw extension. The acceptance criteria in ASME Code, Section XI, K-2200(a)(1) is satisfied. The slope of $J_{applied}$ (SF=1.25) is less than the J-material (J-R curve) at the intersection of both curves (i.e., $J_{applied}$ = J-R). Therefore, the stability acceptance criteria in ASME Code, Section XI, K-2200(a)(2) is satisfied.

Level D

For all evaluated locations, the $J_{applied}$ at 0.1-inch flaw extension with a SF of 1.0 are below the J-R at 0.1-inch flaw extension. The acceptance criteria in ASME Code, Section XI, K-2400(a) is satisfied. The slope of $J_{applied}$ is less than the J-R curve at the intersection of both curves (i.e., $J_{applied}$ = J-R). Therefore, the stability acceptance criteria in ASME Code, Section XI, K-3400 is satisfied. All flaws evaluated for Level D assumed 1/10 thickness (including cladding and limited to 1 inch) plus 0.1-inch flaw extension. This satisfies the 75% of wall thickness requirement per K-2400(c). Additionally, the maximum Level D internal pressure is less than the tensile instability pressures calculated per K-5300 (b) for all evaluated locations and flaws.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The USE analyses have been projected to the end of the subsequent period of extended operation.

Figure 4.2.2-1 Unit 1 - Axial Boundary of the 1.0E+17 n/cm^2 Fluence Threshold in the +Z Direction (at 50.3 EFPY and 72 EFPY)

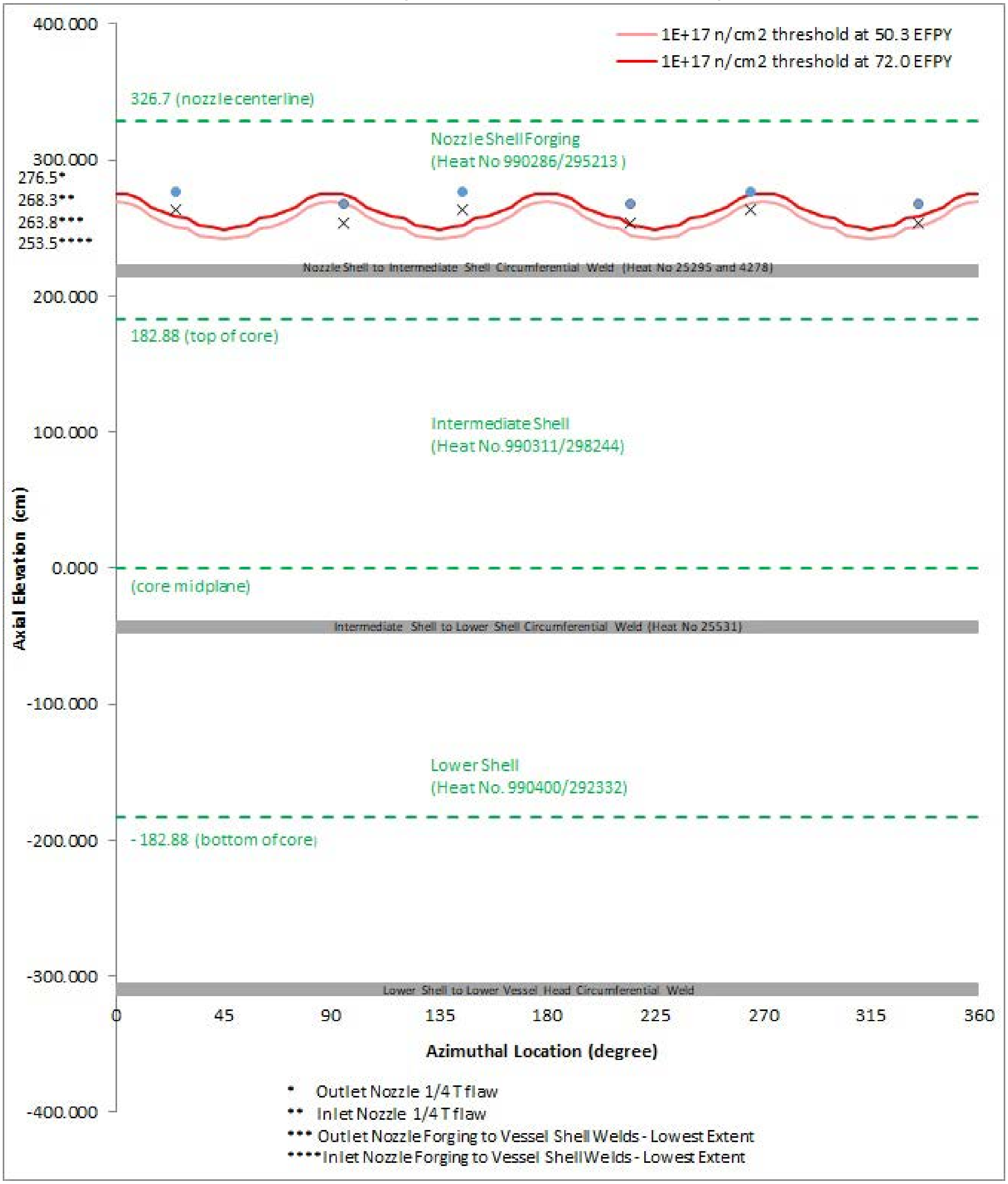

Figure 4.2.2-2 Unit 2 - Axial Boundary of the 1.0E+17 n/cm^2 Fluence Threshold in the +Z Direction (at 52.3 EFPY and 72 EFPY)

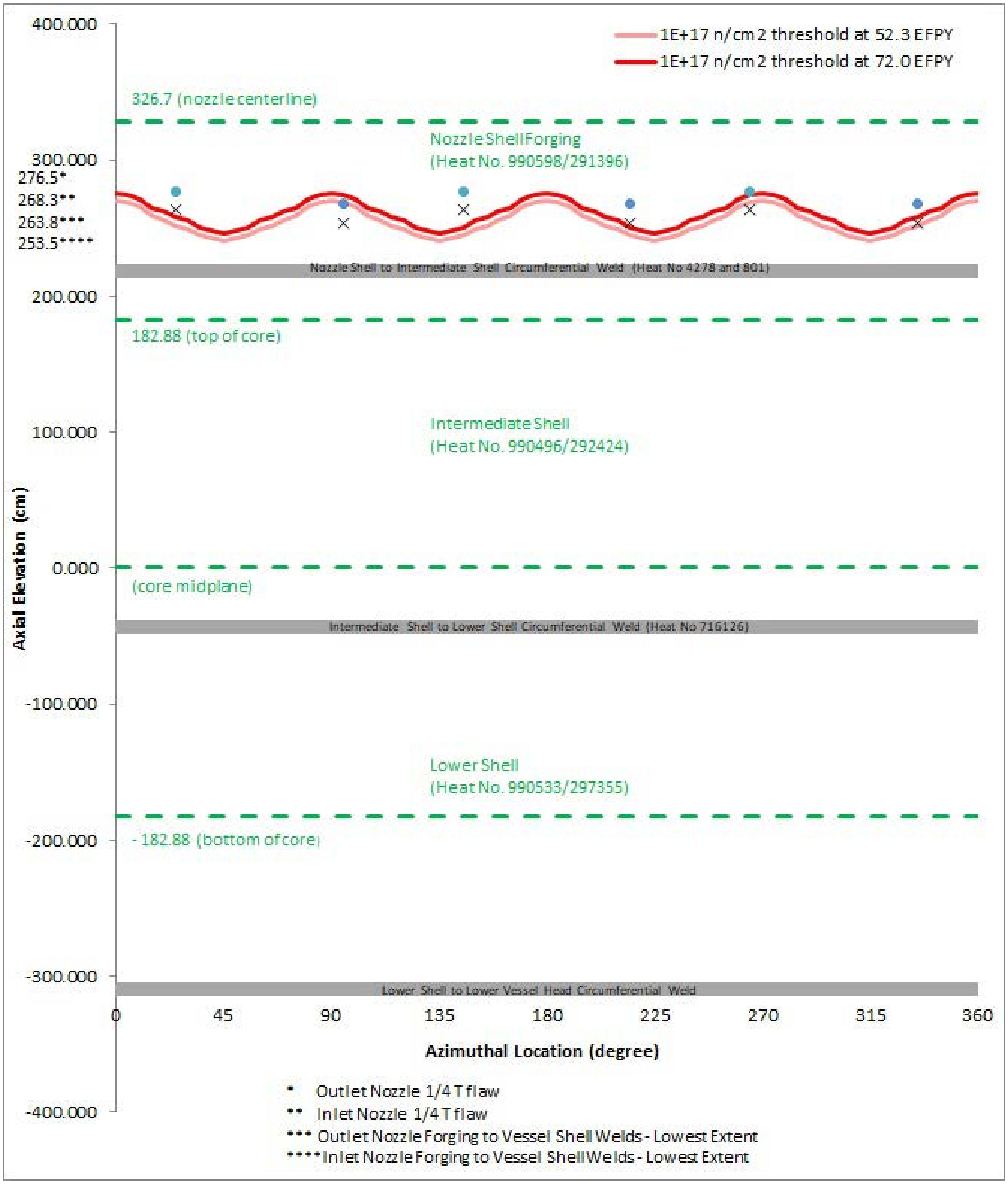

Figure 4.2.2-3 Reactor Vessel - Unit 1 and Unit 2

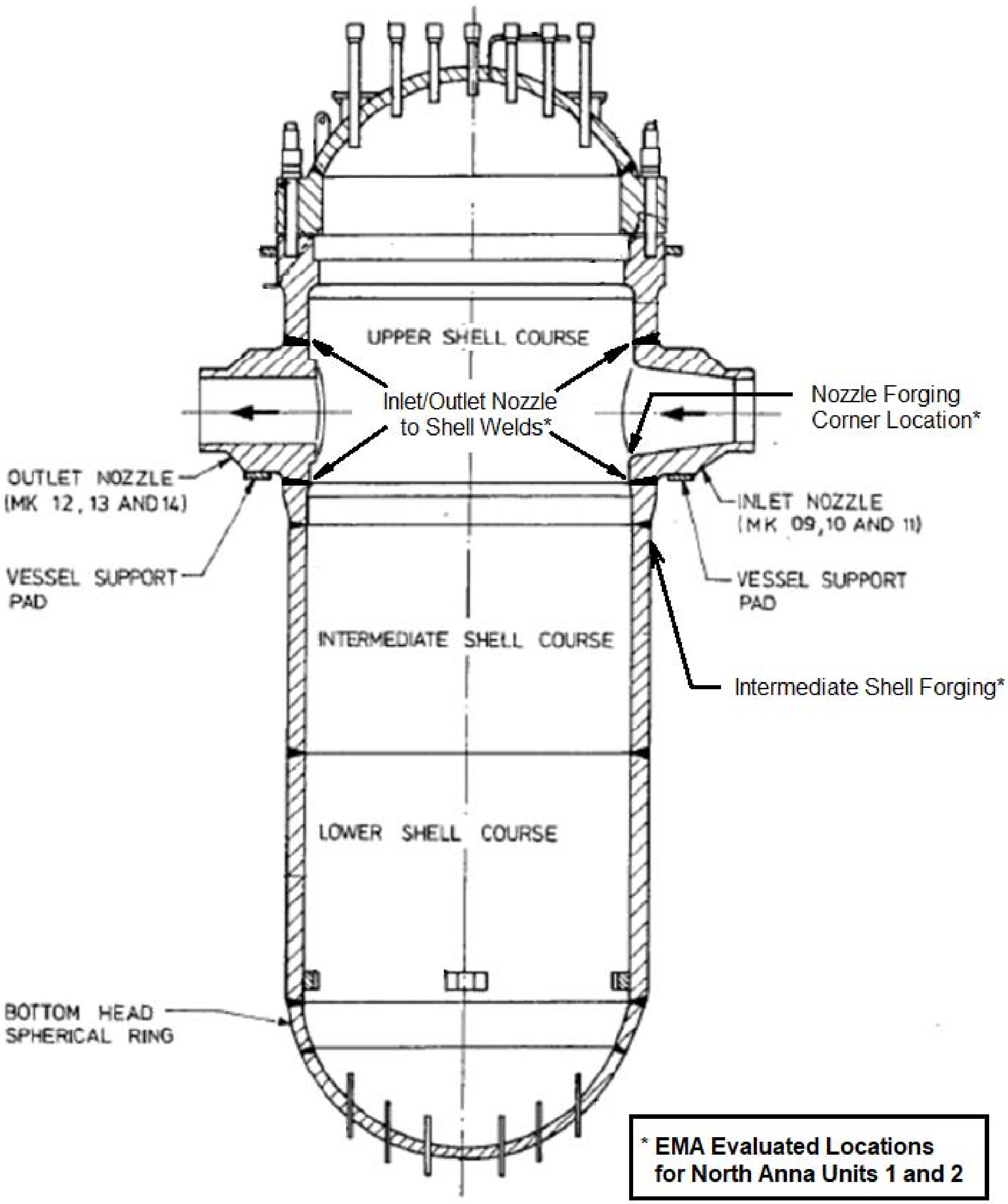

Table 4.2.2-1 Best Estimate Cu and Ni Weight Percent Values, Initial RT_{NDT} Values, and Initial USE Values for the Unit 1 RPV Beltline, Extended Beltline, and Surveillance Materials[(a)]

Material Description	Heat Number	Flux Type (Lot)	Wt.% Cu	Wt.% Ni	$RT_{NDT(U)}$[(b)] (°F)	Initial USE (ft-lbs)[(f)]
Reactor Vessel Beltline Materials						
Upper Shell Forging 05	990286 / 295213	-	0.16	0.74	1	72
Upper to Intermediate Shell Circumferential Weld (94% OD)	25295	SMIT 89 (1170)	0.352	0.125	-40	112
Upper to Intermediate Shell Circumferential Weld (6% ID)	4278	SMIT 89 (1211)	0.12	0.11	-4	105
Intermediate Shell Forging 04	990311 / 298244	-	0.12	0.82	-6	91
Intermediate to Lower Shell Circumferential Weld	25531	SMIT 89 (1211)	0.098	0.124	-2	95
Lower Shell Forging 03	990400 / 292332	-	0.156	0.817	33	85
Reactor Vessel Extended Beltline Materials						
Inlet/Outlet Nozzle to Upper Shell Welds	Rotterdam[(d)]		0.35[(c)]	1.13[(c)]	30[(d)]	72[(c)]
Inlet Nozzle Forging 09	990290-11	-	0.13	0.80	-14	≥ 71
Inlet Nozzle Forging 10	990290-12	-	0.13	0.79	-10	≥ 58
Inlet Nozzle Forging 11	990268-21	-	0.18	0.78	8	56[(c)]
Outlet Nozzle Forging 12	990290-31	-	0.13	0.80	-6	≥ 66
Outlet Nozzle Forging 13	990290-22	-	0.13	0.81	-7	≥ 59
Outlet Nozzle Forging 14	990290-21	-	0.13	0.81	8	≥ 59
Reactor Vessel Surveillance Program Materials[(e)]						
Lower Shell Forging 03	990400 / 292332	-	0.158	0.823	-	-
Intermediate to Lower Shell Circumferential Weld	25531	SMIT 89 (1211)	0.098	0.124	-	-

Notes:

(a) Unless otherwise noted, the information is extracted from PWROG-18005-NP. Dashes indicate when a category is not applicable to the material.

(b) All $RT_{NDT(U)}$ values are based on measured data which are used in conjunction with ASME Code, Section III, and/or BTP 5-3 methods; thus, a σ_I value of 0°F can be used with these $RT_{NDT(U)}$ values per WCAP-14040-A, Revision 4.

(c) Generic value developed in PWROG-17090-NP-A. Inlet Nozzle Forging 11 was supplied by Rheinstahl Huttenwerke AG and is of the ASTM A508, Class 2 specification. The inlet/outlet nozzle to upper shell welds were fabricated by Rotterdam with an unknown weld type. Justification for the use of these values, consistent with the NRC Safety Evaluation, is presented in Appendix D of WCAP-18364-NP.

(d) The specific heat, flux type, and flux lot numbers of these welds could not be identified in the available information; therefore, conservative generic numbers will be used to describe these welds. The $RT_{NDT(U)}$ value was determined using ASME Code, Section III, minimum criteria at the time of fabrication and BTP 5-3, Position 1.1(4) guidance. Since this is a maximum possible value based on measured data that satisfied the ASME Code requirements, the σ_I associated with this $RT_{NDT(U)}$ is zero.

(e) The reactor vessel surveillance material data is taken from Dominion Energy calculation SM-1008.

(f) The evaluations of the updated unirradiated USE values for North Anna Unit 1 are detailed in Attachment 2 of PWROG-18005. Differences between the original and updated unirradiated USE values are a result of the use of a calculational method other than the average of all points with ≥ 95% shear or a result of having chosen a different conservative USE value, unless noted otherwise. A greater than or equal to symbol, "≥", identifies a material with no available upper shelf data; thus, the initial USE values for these materials were conservatively estimated based on the highest recorded absorbed energy points.

Table 4.2.2-2 Best Estimate Cu and Ni Weight Percent Values, Initial RT_{NDT} Values, and Initial USE Values for the Unit 2 RPV Beltline, Extended Beltline, and Surveillance Materials[a]

Material Description	Heat Number	Flux Type (Lot)	Wt.% Cu	Wt.% Ni	$RT_{NDT(U)}$[b] (°F)	Initial USE (ft-lbs)[f]
Reactor Vessel Beltline Materials						
Upper Shell Forging 05	990598 / 291396	-	0.08	0.77	8	72
Upper to Intermediate Shell Circumferential Weld (94% OD)	4278	SMIT 89 (1211)	0.12	0.11	-4	105
Upper to Intermediate Shell Circumferential Weld (6% ID)	801	SMIT 89 (1211)	0.18	0.11	10	75[c]
Intermediate Shell Forging 04	990496 / 292424	-	0.107	0.857	69	72
Intermediate to Lower Shell Circumferential Weld	716126	LW320 (26)	0.066	0.046	-67	109
Lower Shell Forging 03	990533 / 297355	-	0.13	0.83	37	80
Reactor Vessel Extended Beltline Materials						
Inlet/Outlet Nozzle to Upper Shell Welds	8816	LW320 (28)	0.23[c]	0.56[c]	30[d]	75[c]
	20459	LW320 (26)				
	27622	LW320 (26)				
	27622	LW320 (28)				
Inlet Nozzle Forging 09	990426	-	0.19	0.82	11	56[c]
Inlet Nozzle Forging 10	54567-2	-	0.14	0.79	5	≥ 77
Inlet Nozzle Forging 11	54590-2	-	0.155	0.77	-31	≥ 75
Outlet Nozzle Forging 12	990426-22	-	0.19	0.80	8	≥ 60
Outlet Nozzle Forging 13	990426-31	-	0.19	0.79	1	56[c]
Outlet Nozzle Forging 14	791291	-	0.12	0.82	-22	≥ 74
Reactor Vessel Surveillance Program Materials[e]						
Intermediate Shell Forging 04	990496 / 292424	-	0.116	0.886	-	-
Intermediate to Lower Shell Circumferential Weld	716126	LW320 (26)	0.067	0.052	-	-

Notes:

(a) Unless otherwise noted, the information is extracted from PWROG-18005-NP. Dashes indicate when a category is not applicable to the material.

(b) All $RT_{NDT (U)}$ values are based on measured data which are used in conjunction with ASME Code, Section III, and/or BTP 5-3 methods; thus, a σI value of 0°F can be used with these $RT_{NDT(U)}$ values per WCAP-14040-A, Revision 4.

(c) Generic value developed in PWROG-17090-NP-A. Inlet Nozzle Forging 09 and Outlet Nozzle Forging 13 were supplied by Rheinstahl Huttenwerke AG and are of the ASTM A508, Class 2 specification. The inlet/outlet nozzle to upper shell welds were fabricated by Rotterdam with a submerged arc weld (SAW) weld type. Justification for the use of these values, consistent with the NRC Safety Evaluation, is presented in Appendix D of WCAP-18364-NP.

(d) The records do not identify which weld heats are associated with which specific nozzle welds. Therefore, the bounding material properties will be conservatively associated with all Unit 2 nozzle welds. The $RT_{NDT (U)}$ value was determined using ASME Code, Section III, minimum criteria at the time of fabrication and BTP 5-3, Position 1.1(4) guidance. Since this is a maximum possible value based on measured data that satisfied the ASME Code requirements, the σ_I associated with this $RT_{NDT (U)}$ is zero.

(e) The reactor vessel surveillance material data is taken from Dominion Energy calculation SM-1008.

(f) The evaluations of the updated unirradiated USE values for North Anna Unit 1 are detailed in Attachment 2 of PWROG-18005. Differences between the original and updated unirradiated USE values are a result of the use of a calculational method other than the average of all points with ≥ 95% shear or a result of having chosen a different conservative USE value, unless noted otherwise. A greater than or equal to symbol “≥”, identifies a material with no available upper shelf data; thus, the initial USE values for these materials were conservatively estimated based on the highest recorded absorbed energy points.

Table 4.2.2-3 Predicted USE Values at 72 EFPY for Unit 1

Reactor Vessel Material	Heat #	Wt.% Cu[a]	Surf. SLR Fluence[b] (x 10^{19} n/cm^2, E > 1.0 MeV)	1/4T SLR Fluence[c] (x 10^{19} n/cm^2, E > 1.0 MeV)	Unirradiated USE[a] (ft-lbs)	Projected USE Decrease[d] (%)	Projected SLR USE (ft-lbs)
Position 1.2							
Upper Shell Forging 05	990286 / 295213	0.16	0.304	0.192	72	17.0	59.8
Upper to Intermediate Shell Circumferential Weld (OD 94%)	25295	0.352	0.351	0.221	112	34.0	73.9
Upper to Intermediate Shell Circumferential Weld (ID 6%)[g]	4278	0.12	0.351	0.221	105	18.5	85.6
Intermediate Shell Forging 04	990311 / 298244	0.12	7.07	4.46	91	30.0	63.7
Intermediate to Lower Shell Circumferential Weld	25531	0.098	7.04	4.44	95	34.5	62.2
Lower Shell Forging 03	990400 / 292332	0.156	7.20	4.54	85	36.0	54.4
Inlet Nozzle Forging 09 to Upper Shell Weld	Rotterdam	0.35	0.00898	0.00898	72	0.0[f]	72.0
Inlet Nozzle Forging 10 to Upper Shell Weld			0.0313	0.0313	72	26.0	53.3
Inlet Nozzle Forging 11 to Upper Shell Weld			0.0120	0.0120	72	24.0	54.7
Outlet Nozzle Forging 12 to Upper Shell Weld			0.0182	0.0182	72	24.0	54.7
Outlet Nozzle Forging 13 to Upper Shell Weld			0.00522	0.00522	72	0.0[f]	72.0
Outlet Nozzle Forging 14 to Upper Shell Weld			0.00697	0.00697	72	0.0[f]	72.0

Table 4.2.2-3 Predicted USE Values at 72 EFPY for Unit 1

Reactor Vessel Material	Heat #	Wt.% Cu[(a)]	Surf. SLR Fluence[(b)] (x 10^{19} n/cm^2, E > 1.0 MeV)	1/4T SLR Fluence[(c)] (x 10^{19} n/cm^2, E > 1.0 MeV)	Unirradiated USE[(a)] (ft-lbs)	Projected USE Decrease[(d)] (%)	Projected SLR USE (ft-lbs)
Inlet Nozzle Forging 09	990290-11	0.13	0.00898	0.00898	71	0.0[(f)]	71.0
Inlet Nozzle Forging 10	990290-12	0.13	0.0313	0.0313	58	10.0	52.2
Inlet Nozzle Forging 11	990268-21	0.18	0.0120	0.0120	56	10.7[(h)]	**50.0[(h)]**
Outlet Nozzle Forging 12	990290-31	0.13	0.0182	0.0182	66	9.0	60.1
Outlet Nozzle Forging 13	990290-22	0.13	0.00522	0.00522	59	0.0[(f)]	59.0
Outlet Nozzle Forging 14	990290-21	0.13	0.00697	0.00697	59	0.0[(f)]	59.0
Position 2.2[(e)]							
Intermediate to Lower Shell Circumferential Weld	25531	0.098	7.04	4.44	95	27.0	69.4[(i)]
Lower Shell Forging 03	990400 / 292332	0.156	7.20	4.54	85	36.0	54.4[(i)]

Notes:

(a) Copper weight percent values and unirradiated USE values were taken from Table 3-1 of WCAP-18364-NP.

(b) Surface fluence values taken from Table 4.2.1-1

(c) The 1/4T fluence values were calculated from the surface fluence, the reactor vessel beltline thickness (7.677 inches) and equation $f = f_{surf} * e^{-0.24\ (x)}$ from Regulatory Guide 1.99, Revision 2, where x = the depth into the vessel wall (inches). The surface fluence at the lowest extent of the nozzle to upper shell weld centerline was used to represent the inlet and outlet nozzle forgings and associated welds. 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 percent decrease because 2 x 10^{17} n/cm^2 is the lowest fluence displayed in Figure 2 of the Regulatory Guide.

(d) The Position 1.2 USE decrease values were calculated by plotting the 1/4T fluence values onto Figure 2 of Regulatory Guide 1.99, Revision 2 and using the material-specific Cu wt.% values. Base metal and weld Cu wt.% lines were extended into the low fluence area of Regulatory Guide 1.99, Revision 2, Figure 2 (i.e., below 10^{18} n/cm^2) in order to determine the USE percent decrease as needed.

(e) Calculated using surveillance capsule measured percent decrease in USE from BAW-2356 and Regulatory Guide 1.99, Revision 2, Position 2.2.

(f) Embrittlement effects only need to be considered if the fluence is greater than 10^{17} n/cm^2 (E > 1.0 MeV).

(g) Since this inner diameter (ID) weld is only 6% of the vessel thickness, the weld is not present at the 1/4T location; hence, it is not applicable to this calculation. It is presented for information only.

(h) The Unit 1 Inlet Nozzle 11 USE value is set equal to 50 ft-lbs which results in a projected drop of 10.7%. A review of Regulatory Guide 1.99, Revision 2, Figure 2 resulted in a conservative estimate of approximately 11%, but the figure has limited precision. A decrease of 10.7% is considered appropriate based on the following conservatism in the calculations. The estimated percent decrease is based on a fluence of 2 x 10^{17} n/cm^2 (E > 1.0 MeV), which is the lowest fluence line displayed in Regulatory Guide 1.99, Revision 2, Figure 2. The actual fluence is projected to be roughly half this, i.e. 1.20 x 10^{17} n/cm^2 (E > 1.0 MeV), at the lowest extent of the nozzle weld and would be even lower at higher axial elevations. In addition, the fluence would be further decreased if attenuation to the 1/4T location were considered. These additional decreases in fluence would raise the projected USE of Unit 1 Inlet Nozzle 11 above 50 ft-lbs.

(i) Position 2.2 was used to determine the Unit 1 Lower Shell Forging 03 and the Intermediate to Lower Shell Weld USE value even though the surveillance data were deemed non-credible per Appendix A of WCAP-18364-NP. Per Regulatory Guide 1.99, Revision 2, this is appropriate since the upper shelf can be clearly determined from the surveillance test results.

Table 4.2.2-4 Predicted USE Values at 72 EFPY for Unit 2

Reactor Vessel Material	Heat #	Wt.% Cu[(a)]	Surf. SLR Fluence[(b)] (x 10^{19} n/cm^2, E > 1.0 MeV)	1/4T SLR Fluence[(c)] (x 10^{19} n/cm^2, E > 1.0 MeV)	Unirradiated USE[(a)] (ft-lbs)	Projected USE Decrease[(d)] (%)	Projected SLR USE (ft-lbs)
Position 1.2							
Upper Shell Forging 05	990598 / 291396	0.08	0.307	0.194	72	13.0	62.6
Upper to Intermediate Shell Circumferential Weld (OD 94%)	4278	0.12	0.355	0.224	105	18.5	85.6
Upper to Intermediate Shell Circumferential Weld (ID 6%)[(g)]	801	0.18	0.355	0.224	75	23.0	57.8
Intermediate Shell Forging 04	990496 / 292424	0.107	7.20	4.54	72	28.0	51.8
Intermediate to Lower Shell Circumferential Weld	716126	0.066	7.18	4.53	109	29.0	77.4
Lower Shell Forging 03	990533 / 297355	0.13	7.34	4.63	80	32.0	54.4
Inlet Nozzle Forging 09 to Upper Shell Weld	8816 20459 27622	0.23	0.00826	0.00826	75	0.0[(f)]	75.0
Inlet Nozzle Forging 10 to Upper Shell Weld			0.0314	0.0314	75	17.0	62.3
Inlet Nozzle Forging 11 to Upper Shell Weld			0.0118	0.0118	75	15.0	63.8
Outlet Nozzle Forging 12 to Upper Shell Weld			0.0182	0.0182	75	15.0	63.8
Outlet Nozzle Forging 13 to Upper Shell Weld			0.00479	0.00479	75	0.0[(f)]	75.0
Outlet Nozzle Forging 14 to Upper Shell Weld			0.00687	0.00687	75	0.0[(f)]	75.0
Inlet Nozzle Forging 09	990426	0.19	0.00826	0.00826	56	0.0[(f)]	56.0

Table 4.2.2-4 Predicted USE Values at 72 EFPY for Unit 2

Reactor Vessel Material	Heat #	Wt.% Cu[(a)]	Surf. SLR Fluence[(b)] (x 10^{19} n/cm^2, E > 1.0 MeV)	1/4T SLR Fluence[(c)] (x 10^{19} n/cm^2, E > 1.0 MeV)	Unirradiated USE[(a)] (ft-lbs)	Projected USE Decrease[(d)] (%)	Projected SLR USE (ft-lbs)
Inlet Nozzle Forging 10	54567-2	0.14	0.0314	0.0314	77	10.5	68.9
Inlet Nozzle Forging 11	54590-2	0.155	0.0118	0.0118	75	10.0	67.5
Outlet Nozzle Forging 12	990426-22	0.19	0.0182	0.0182	60	11.5	53.1
Outlet Nozzle Forging 13	990426-31	0.19	0.00479	0.00479	56	0.0[(f)]	56.0
Outlet Nozzle Forging 14	791291	0.12	0.00687	0.00687	74	0.0[(f)]	74.0
Position 2.2[(e)]							
Intermediate Shell Forging 04	990496 / 292424	0.107	7.20	4.54	72	33.0	**48.2**[(h)]
Intermediate to Lower Shell Circumferential Weld	716126	0.066	7.18	4.53	109	28.0	78.5

Notes:

(a) Copper weight percent values and unirradiated USE values were taken from Table 3-2 of WCAP-18364-NP.

(b) Surface fluence values taken from Table 4.2.1-2.

(c) The 1/4T fluence values were calculated from the surface fluence, the reactor vessel beltline thickness (7.677 inches) and equation $f = f_{surf} * e^{-0.24(x)}$ from Regulatory Guide 1.99, Revision 2, where x = the depth into the vessel wall (inches). The surface fluence at the lowest extent of the nozzle to upper shell weld centerline was used to represent the inlet and outlet nozzle forgings and associated welds. 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 percent decrease because 2 x 10^{17} n/cm^2 is the lowest fluence displayed in Figure 2 of the Regulatory Guide.

(d) The Position 1.2 USE decrease values were calculated by plotting the 1/4T fluence values onto Figure 2 of Regulatory Guide 1.99, Revision 2 and using the material-specific Cu wt.% values. Base metal and weld Cu wt.% lines were extended into the low fluence area of Regulatory Guide 1.99, Revision 2, Figure 2 (i.e., below 10^{18} n/cm^2) in order to determine the USE percent decrease as needed.

(e) Calculated using surveillance capsule measured percent decrease in USE from BAW-2376 and Regulatory Guide 1.99, Revision 2, Position 2.2.

(f) Embrittlement effects only need to be considered if the fluence is greater than 10^{17} n/cm^2 (E > 1.0 MeV).

(g) Since this inner diameter (ID) weld is only 6% of the vessel thickness, the weld is not present at the 1/4T location; hence, it is not applicable to this calculation. It is presented for information only.

(h) Position 2.2 was used to determine the Unit 2 Intermediate Shell Forging 04 USE value even though its surveillance data was deemed non-credible per Appendix A of WCAP-18364-NP. Per Regulatory Guide 1.99, Revision 2, this is appropriate since the upper shelf can be clearly determined from the surveillance test results.

4.2.3 PRESSURIZED THERMAL SHOCK

TLAA Description:

A limiting condition on RV integrity known as Pressurized Thermal Shock (PTS) may occur during a severe system transient such as a small-break loss-of-coolant accident (LOCA) or steam line break. Such transients may challenge the integrity of the RV under the following conditions: severe overcooling of the inside surface of the vessel wall followed by repressurization, significant degradation of vessel material toughness caused by radiation embrittlement, and the presence of a critical-size defect anywhere within the vessel wall.

10 CFR 50.61(b)(1) (Reference 1.7-15) provides rules for protection against PTS events for pressurized water reactors. Licensees are required to perform an updated assessment of the projected values of the PTS reference temperature (RT_{PTS}) whenever there is a significant change in projected values of RT_{PTS} or upon a request for a change in the expiration date for operation of the facility. The current analyses, evaluated for 50.3 EFPY fluence values for Unit 1, and 52.3 EFPY fluence values for Unit 2, predicted for 60 years of operation, are TLAAs requiring evaluation for 80 years since a change in the operating license term of the facility is being requested.

TLAA Evaluation:

10 CFR 50.61(c) provides two methods for determining RT_{PTS}. These methods are also described as Positions 1 and 2 in Regulatory Guide 1.99, Revision 2. Position 1 applies for material without credible surveillance data available and Position 2 is used for material with two or more credible surveillance data sets available. The RT_{PTS} values are calculated for both Positions 1 and 2 by following the guidance in Regulatory Guide 1.99, Revision 2 (Sections 1.1 and 2.1, respectively), using the copper and nickel content of the Units 1 and 2 beltline materials, and subsequent period of extended operation fluence projections.

These accepted methods were used with the surface fluence values above to calculate the following RT_{PTS} values for the Units 1 and 2 RV materials at 72 EFPY. The subsequent period of extended operation RT_{PTS} calculations are summarized in Table 4.2.3-1 and Table 4.2.3-2 for Units 1 and 2, respectively.

PWROG-18005-NP, summarizes the results and methodologies used in the determination of the unirradiated nil ductility transition temperature (RT_{NDT}) for the Units 1 and 2 RV materials.

WCAP-18364-NP provides the RT_{PTS} calculations for the beltline and extended beltline materials.

10 CFR 50.61(b)(2) establishes screening criteria for RT_{PTS} as 270°F for plates, forgings, and longitudinal welds and 300°F for circumferential welds.

All of the beltline materials in the Units 1 and 2 RV are below the RT_{PTS} screening criteria values of 270°F for base metal and longitudinal welds, and 300°F for circumferentially oriented welds through the subsequent period of extended operation. It is recognized in SECY-82-465, “Pressurized Thermal Shock (PTS)” (Reference 4.8-20), Enclosure A, that the RT_{PTS} screening criteria values of 270°F for base metal and longitudinal welds, and 300°F for circumferentially oriented welds are applicable to cylindrical beltline materials. The adjusted reference temperatures for all extended beltline materials are well below 270°F.

The Units 1 and 2 limiting RT_{PTS}value for base metal or longitudinal weld materials at 72 EFPY is 212.2°F (see Table 4.2.3-1 and Table 4.2.3-2), which corresponds to Unit 2 Lower Shell Forging 03 based on Regulatory Guide 1.99, Revision 2, Position 1.1. Note that the RT_{PTS} value calculated for Unit 1 Lower Shell Forging 03 (243°F) is higher. However, the use of the lesser (212.2°F) of the Regulatory Guide 1.99, Revision 2, Position 1.1 and 2.1 chemistry factor (CF) with non-credible data and a full margin term is justified since none of the surveillance data are more than two times sigma-delta above the Position 1.1 CF trend line. This determination is documented in Appendix C of WCAP-18364-NP. The Units 1 and 2 limiting RT_{PTS} value for circumferentially oriented welds at 72 EFPY is 136.3°F, which corresponds to the Unit 1 Intermediate to Lower Shell Circumferential Weld Heat # 25531 based on Regulatory Guide 1.99, Revision 2, Position 1.1. Note that the RT_{PTS} value for this material using the Position 2.1 CF is higher. However, per the discussion in Appendix C of WCAP-18364-NP, the lower of the Position 1.1 and Position 2.1 CF can be used for this material. These limiting materials are consistent with the previous 60-year analysis.

WCAP-18364-NP provides RT_{PTS} calculations for the nozzle materials. The Units 1 and 2 materials remain below the 10 CFR 50.61 screening criteria.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The PTS analyses have been projected to the end of the subsequent period of extended operation

Table 4.2.3-1 Calculation of Unit 1 RT_{PTS} Values at 72 EFPY at the Clad/Base Metal Interface

Material	Heat Number	Flux Type (Lot)	CF[(b)]	Surface Fluence[(c)] (x 10^{19} n/cm^2, E > 1.0 MeV)	Surf. FF[(d)]	$RT_{NDT(U)}$[(e)] (°F)	Predicted ΔRT_{NDT} (°F)	σ_U[(f)] (°F)	σ_Δ[(g)] (°F)	M (°F)	RT_{PTS} (°F)
Reactor Vessel Beltline Materials											
Upper Shell Forging 05	990286 / 295213	-	121.50	0.304	0.674	1	81.9	0.0	17.0	34.0	116.9
Upper to Intermediate Shell Circumferential Weld (OD 94%)[(k)]	25295	SMIT 89 (1170)	163.25	0.351	0.711	-40	116.1	0.0	28.0	56.0	132.1
Using credible surveillance data[(h)]			150.69	0.351	0.711	-40	107.2	0.0	14.0	28.0	95.2
Upper to Intermediate Shell Circumferential Weld (ID 6%)	4278	SMIT 89 (1211)	63.00	0.351	0.711	-4	44.8	0.0	22.4	44.8	85.6
Using non-credible surveillance data[(i)]			80.71	0.351	0.711	-4	57.4	0.0	28.0	56.0	109.4
Intermediate Shell Forging 04	990311 / 298244	-	86.00	7.07	1.464	-6	125.9	0.0	17.0	34.0	153.9
Intermediate to Lower Shell Circumferential Weld	25531	SMIT 89 (1211)	56.22	7.04	1.464	-2	82.3	0.0	28.0	56.0	136.3
Using non-credible surveillance data[(j)]			67.53	7.04	1.464	-2	98.9	0.0	28.0	56.0	152.9
Lower Shell Forging 03	990400 / 292332	-	119.97	7.20	1.467	33	176.0	0.0	17.0	34.0	243.0
Using non-credible surveillance data[(j)]			81.68	7.20	1.467	33	119.9	0.0	17.0	34.0	**186.9**

Table 4.2.3-1 Calculation of Unit 1 RT_{PTS} Values at 72 EFPY at the Clad/Base Metal Interface

Material	Heat Number	Flux Type (Lot)	CF[(b)]	Surface Fluence[(c)] (x 10^{19} n/cm^2, E > 1.0 MeV)	Surf. FF[(d)]	$RT_{NDT(U)}$[(e)] (°F)	Predicted ΔRT_{NDT} (°F)	σ_U[(f)] (°F)	σ_Δ[(g)] (°F)	M (°F)	RT_{PTS} (°F)
Reactor Vessel Beltline Materials											
Inlet Nozzle Forging 09 to Upper Shell Weld	Rotterdam	-	293.45	0.00898	0	30	0.0	0.0	0.0	0.0	30.0
Inlet Nozzle Forging 10 to Upper Shell Weld				0.0313	0.225	30	66.1	0.0	28.0	56.0	152.1
Inlet Nozzle Forging 11 to Upper Shell Weld				0.0120	0.124	30	36.4	0.0	18.2	36.4	102.7
Outlet Nozzle Forging 12 to Upper Shell Weld				0.0182	0.162	30	47.6	0.0	23.8	47.6	125.2
Outlet Nozzle Forging 13 to Upper Shell Weld				0.00522	0	30	0.0	0.0	0.0	0.0	30.0
Outlet Nozzle Forging 14 to Upper Shell Weld				0.00697	0	30	0.0	0.0	0.0	0.0	30.0
Inlet Nozzle Forging 09	990290-11	-	96.00	0.00898	0	-14	0.0	0.0	0.0	0.0	-14
Inlet Nozzle Forging 10	990290-12	-	95.75	0.0313	0.225	-10	21.6	0.0	10.8	21.6	33.1
Inlet Nozzle Forging 11	990268-21	-	140.30	0.0120	0.124	8	17.4	0.0	8.7	17.4	42.8
Outlet Nozzle Forging 12	990290-31	-	96.00	0.0182	0.162	-6	15.6	0.0	7.8	15.6	25.1
Outlet Nozzle Forging 13	990290-22	-	96.00	0.00522	0	-7	0.0	0.0	0.0	0.0	-7.0
Outlet Nozzle Forging 14	990290-21	-	96.00	0.00697	0	8	0.0	0.0	0.0	0.0	8.0

Notes:

(a) The 10 CFR 50.61 methodology was utilized in the calculation of the RT_{PTS} values.

(b) Chemistry factors are taken from Table 3-7 of WCAP-18364-NP.

(c) Fluence is taken from Table 4.2.1-1. The surface fluence at the lowest extent of the nozzle to upper shell weld centerline was used to represent the inlet and outlet nozzle forgings and associated welds.

(d) FF = fluence factor = $f^{(0.28 - 0.10*\log(f))}$. Embrittlement effects are considered only if the fluence is greater than 10^{17} n/cm^2. For materials with fluence less than 10^{17} n/cm^2 the FF is set equal to 0.

(e) $RT_{NDT(U)}$ values are taken from Table 4.2.2-3.

(f) The initial RT_{NDT} values are based on measured values; therefore σ_U = 0°F.

(g) Per 10 CFR 50.61, the base metal σ_Δ = 17°F for Position 1.1 and Position 2.1 with non-credible surveillance data. Also, per 10 CFR 50.61, the weld metal σ_Δ = 28°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and σ_Δ = 14°F for Position 2.1 with credible surveillance data. However, σ_Δ need not exceed $0.5*\Delta RT_{NDT}$.

(h) The surveillance data for weld Heat # 25295 from the Sequoyah Unit 1 surveillance program were deemed credible per WCAP-17539-NP.

(i) The surveillance data for weld Heat # 4278 from the Sequoyah Unit 2 surveillance program were deemed non-credible per WCAP-17539-NP.

(j) The credibility evaluation for the Unit 1 surveillance data in Appendix A.1 of WCAP-18364-NP determined that the Lower Shell Forging 03 and weld Heat # 25531 surveillance data are deemed non-credible.

(k) While 10 CFR 50.61 specifically requires the analysis be performed at the surface and this material is not present at the surface, it is still included as it represents the majority of the weld.

Table 4.2.3-2 Calculation of Unit 2 RT_{PTS} Values at 72 EFPY at the Clad/Base Metal Interface

Material	Heat Number	Flux Type (Lot)	CF[b]	Surface Fluence[c] (x 10^{19} n/cm^2, E>1.0 MeV)	Surf. FF[d]	$RT_{NDT(U)}$[e] (°F)	Predicted ΔRT_{NDT} (°F)	σ_U[f] (°F)	σ_Δ[g] (°F)	M (°F)	RT_{PTS} (°F)
Reactor Vessel Beltline Materials											
Upper Shell Forging 05	990598 / 291396	-	51.00	0.307	0.676	8	34.5	0.0	17.0	34.0	76.5
Upper to Intermediate Shell Circumferential Weld (OD 94%)[j]	4278	SMIT 89 (1211)	63.00	0.355	0.714	-4	45.0	0.0	22.5	45.0	86.0
Using non-credible surveillance data[h]			80.71	0.355	0.714	-4	57.6	0.0	28.0	56.0	109.6
Upper to Intermediate Shell Circumferential Weld (ID 6%)	801	SMIT 89 (1211)	87.80	0.355	0.714	10	62.7	0.0	28.0	56.0	128.7
Intermediate Shell Forging 04	990496 / 292424	-	74.00	7.20	1.467	69	108.6	0.0	17.0	34.0	211.6
Using non-credible surveillance data[i]			53.44	7.20	1.467	69	78.4	0.0	17.0	34.0	181.4
Intermediate to Lower Shell Circumferential Weld	716126	LW32 (26)	36.09	7.18	1.467	-67	52.9	0.0	26.5	52.9	38.9
Using credible surveillance data[i]			26.61	7.18	1.467	-67	39.0	0.0	14.00	28.0	0.0
Lower Shell Forging 03	990533 / 297355	-	96.00	7.34	1.470	37	141.2	0.0	17.00	34.0	**212.2**

Table 4.2.3-2 Calculation of Unit 2 RT_{PTS} Values at 72 EFPY at the Clad/Base Metal Interface

Material	Heat Number	Flux Type (Lot)	CF[b]	Surface Fluence[c] (x 10^{19} n/cm^2, E >1.0 MeV)	Surf. FF[d]	$RT_{NDT(U)}$[e] (°F)	Predicted ΔRT_{NDT} (°F)	σ_U[f] (°F)	σ_Δ[g] (°F)	M (°F)	RT_{PTS} (°F)
Reactor Vessel Extended Beltline Materials											
Inlet Nozzle Forging 09 to Upper Shell Weld	8816 20459 27622	LW320 (26 & 28)	163.20	0.00826	0	30[k]	0.0	0.0	0.0	0.0	30.0
Inlet Nozzle Forging 10 to Upper Shell Weld			163.20	0.0314	0.226	30[k]	36.8	0.0	18.4	36.8	103.6
Inlet Nozzle Forging 11 to Upper Shell Weld			163.20	0.0118	0.123	30[k]	20.0	0.0	10.0	20.0	70.0
Outlet Nozzle Forging 12 to Upper Shell Weld			163.20	0.0182	0.162	30[k]	26.5	0.0	13.2	26.5	82.9
Outlet Nozzle Forging 13 to Upper Shell Weld			163.20	0.00479	0	30[k]	0.0	0.0	0.0	0.0	30.0
Outlet Nozzle Forging 14 to Upper Shell Weld			163.20	0.00687	0	30[k]	0.0	0.0	0.0	0.0	30.0
Inlet Nozzle Forging 09	990426	-	150.40	0.00826	0	11	0.0	0.0	0.0	0.0	11.0
Inlet Nozzle Forging 10	54567-2	-	104.75	0.0314	0.226	5	23.6	0.0	11.8	23.6	52.3
Inlet Nozzle Forging 11	54590-2	-	118.25	0.0118	0.123	-31	14.5	0.0	7.2	14.5	-2.0
Outlet Nozzle Forging 12	990426-22	-	150.00	0.0182	0.162	8	24.3	0.0	12.2	24.3	56.7
Outlet Nozzle Forging 13	990426-31	-	149.60	0.00479	0	1	0.0	0.0	0.0	0.0	1.0
Outlet Nozzle Forging 14	791291	-	86.00	0.00687	0	-22	0.0	0.0	0.0	0.0	-22.0

Notes:

(a) The 10 CFR 50.61 methodology was utilized in the calculation of the RT_{PTS} values.

(b) Chemistry factors are taken from Table 3-8 of WCAP-18364-NP.

(c) Fluence is taken from Table 4.2.1-2. The surface fluence at the lowest extent of the nozzle to upper shell weld centerline was used to represent the inlet and outlet nozzle forgings and associated welds.

(d) FF = fluence factor = $f^{(0.28 - 0.10*\log(f))}$. Embrittlement effects are considered only if the fluence is greater than 10^{17} n/cm^2. For materials with fluence less than 10^{17} n/cm^2 the FF is set equal to 0.

(e) $RT_{NDT\ (U)}$ values are taken from Table 4.2.2-4.

(f) The initial RT_{NDT} values are based on measured values; therefore σ_U = 0°F.

(g) Per 10 CFR 50.61, the base metal σ_Δ = 17°F for Position 1.1 and Position 2.1 with non-credible surveillance data. Also, per 10 CFR 50.61, the weld metal σ_Δ = 28°F for Position 1.1 and Position 2.1 with non-credible surveillance data, and σ_Δ = 14°F for Position 2.1 with credible surveillance data. However, σ_Δ need not exceed $0.5*\Delta RT_{NDT}$.

(h) The surveillance data for weld Heat # 4278 from the Sequoyah Unit 2 surveillance program were deemed non-credible per WCAP-17539-NP.

(i) The credibility evaluation for the Unit 2 surveillance data in Appendix A.2 of WCAP-18364-NP determined that the Intermediate Shell Forging 04 surveillance data are deemed non-credible; however, the weld Heat # 716126 surveillance data are deemed credible.

(j) While 10 CFR 50.61 specifically requires the analysis be performed at the surface and this material is not present at the surface, it is still included as it represents the majority of the weld.

(k) The $RT_{NDT\ (U)}$ is based on the highest $RT_{NDT\ (U)}$ of the heats associated with this weld.

4.2.4 ADJUSTED REFERENCE TEMPERATURE

TLAA Description:

The adjusted reference temperature (ART) of the limiting beltline material is used to adjust the beltline P-T limit curves to account for irradiation effects. Regulatory Guide 1.99, Revision 2, provides the methodology for determining the ART of the limiting material. The initial nil-ductility reference temperature, RT_{NDT}, is the temperature at which a non-irradiated metal (ferritic steel) changes in fracture characteristics from ductile to brittle behavior. Neutron fluence increases the RT_{NDT} beyond its initial value.

RT_{NDT} was evaluated in accordance with PWROG-18005-NP, which includes the generally accepted techniques outlined in:

- ASME Code, Section III, Paragraph NB 2331, “Material for Vessel” (Reference 4.8-21),
- Branch Technical Position 5-3, “Fracture Toughness Requirements” (Reference 4.8-22), and
- BAW-2224, “North Anna Units 1 and 2 Response to Closure Letter for NRC Generic Letter 92-01, Revision 1" (Reference 4.8-23).

10 CFR 50, Appendix G, defines the fracture toughness requirements for the vessel. The shift in the initial RT_{NDT} (ΔRT_{NDT}) is evaluated as the difference in the 30 ft-lbs 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 the sum of the initial (unirradiated) reference temperature (Initial RT_{NDT}), the mean value of the adjustment in reference temperature caused by irradiation (ΔRT_{NDT}), and a margin (M) term.

Since the ΔRT_{NDT} value is a function of 50.3 EFPY fluence for Unit 1, and 52.3 EFPY fluence for Unit 2, associated with the 60 year licensed operating period, these ART calculations meet the criteria of 10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for 80 years.

TLAA Evaluation:

As described in Section 4.2.1, 72 EFPY fluence values were determined for the Units 1 and 2 RV beltline and extended beltline components. These 72 EFPY 1/4T fluence values were used to compute the ART values of Units 1 and 2, in accordance with Regulatory Guide 1.99, Revision 2.

Table 4.2.4-1 through 4.2.4-9 summarize the nozzle, and 1/4T ART calculations for Unit 1 at 50.3 and 72 EFPY and Unit 2 at 52.3 and 72 EFPY. The 3/4T ART values are included in WCAP-18364-NP. The limiting ART values for Units 1 and 2 apply to the Unit 2 Lower Shell Forging 03.

The inlet and outlet nozzle forging ARTs are necessary to perform a nozzle corner fracture mechanics analysis. The nozzle forging ART calculations utilize the postulated nozzle forging surface 1/4T flaw fluence values in order to provide a conservative estimate of the fluence at the limiting nozzle corner location. The nozzle ART values are also considered herein because the nozzle fluence values for some nozzle materials exceed 1.0×10^{17} n/cm^2 (E > 1.0 MeV), and thus all the nozzle forgings are considered part of the extended beltline for conservatism. Since the surface fluence values are utilized for the ART calculations for the nozzle forging materials, the nozzle forgings are omitted from 1/4T ART calculations.

Table 4.2.4-9 compares the TLAA limiting ART values at 50.3 and 72 EFPY for Unit 1 and 52.3 and 72 EFPY for Unit 2 to the limiting ART values used in development of the current Technical Specification P-T limit curves documented in WCAP-15112, “North Anna Units 1 and 2 WOG Reactor Vessel 60-Year Evaluation Minigroup Heatup and Cooldown Limit Curves for Normal Operation” (Reference 4.8-24). The limiting ART values used to develop the existing P-T limit curves are summarized in Table 4.2.4-9. As shown in Table 4.2.4-9, the TLAA limiting ART values at 50.3 EFPY for Unit 1, 52.3 EFPY for Unit 2 and 72 EFPY for both units are less than the limiting ART values used to develop the existing P-T limit curves. Appendix B of WCAP-18363-NP, “North Anna Units 1 and 2 Heatup and Cooldown Limit Curves for Normal Operation” (Reference 4.8-25), shows that the P-T curves for the nozzles lie above and to the left of the P-T curves for the beltline materials. Thus, the P-T curves for the beltline materials are bounding through the subsequent period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii).

The ART analyses have been projected to the end of the subsequent period of extended operation. They may be used as inputs to 72 EFPY P-T limits for the subsequent period of extended operation.

Table 4.2.4-1 Calculation of the Unit 1 Nozzle ART Values at the Surface Location for the Extended Beltline Materials at 50.3 EFPY

Material	Heat Number	Flux Type (Lot)	R.G.1.99, Rev. 2 Position	CF(b)	Surface Fluence(c) (x 10^{19} n/cm^2, E > 1.0 MeV)	Surf. FF(d)	$RT_{NDT(U)}$ (e) (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ (f) (°F)	M (°F)	ART (°F)
Inlet Nozzle Forging 09 to Upper Shell Weld	Rotterdam	-	1.1	293.45	0.00617	0	30	0.0	0.0	0.0	0.0	30.0
Inlet Nozzle Forging 10 to Upper Shell Weld	Rotterdam	-	1.1	293.45	0.0219	0.182	30	53.4	0.0	26.7	53.4	136.8
Inlet Nozzle Forging 11 to Upper Shell Weld	Rotterdam	-	1.1	293.45	0.00833	0	30	0.0	0.0	0.0	0.0	30.0
Outlet Nozzle Forging 12 to Upper Shell Weld	Rotterdam	-	1.1	293.45	0.0127	0.129	30	37.8	0.0	18.9	37.8	105.5
Outlet Nozzle Forging 13 to Upper Shell Weld	Rotterdam	-	1.1	293.45	0.00359	0	30	0.0	0.0	0.0	0.0	30.0
Outlet Nozzle Forging 14 to Upper Shell Weld	Rotterdam	-	1.1	293.45	0.00484	0	30	0.0	0.0	0.0	0.0	30.0
Inlet Nozzle Forging 09	990290-11	-	1.1	96.00	0.00292	0	-14	0.0	0.0	0.0	0.0	-14.0
Inlet Nozzle Forging 10	990290-12	-	1.1	95.75	0.0104	0.113	-10	10.8	0.0	5.4	10.8	11.6
Inlet Nozzle Forging 11	990268-21	-	1.1	140.3	0.00394	0	8	0.0	0.0	0.0	0.0	8.0
Outlet Nozzle Forging 12	990290-31	-	1.1	96.00	0.00612	0	-6	0.0	0.0	0.0	0.0	-6.0
Outlet Nozzle Forging 13	990290-22	-	1.1	96.00	0.00172	0	-7	0.0	0.0	0.0	0.0	-7.0
Outlet Nozzle Forging 14	990290-21	-	1.1	96.00	0.00233	0	8	0.0	0.0	0.0	0.0	8.0

Notes:

(a) The Regulatory Guide 1.99, Revision 2 methodology was utilized in the calculation of the ART values.

(b) Chemistry factors are taken from Table 3-7 of WCAP-18364-NP.

(c) Fluence is taken from Table 4.2.1-1. The fluence values for the nozzle forgings are taken at the postulated 1/4T flaw axial location. The fluence values for the inlet/outlet nozzle to upper shell welds are taken at the lowest extent of the nozzle weld centerline. Analysis of the nozzle forgings and associated welds are conservatively performed using the surface fluence, neglecting attenuation through the reactor vessel wall. Embrittlement effects are considered only if the fluence is greater than 10^{17} n/cm^2. For materials with fluence less than 10^{17} n/cm^2 the FF is set equal to 0.

(d) FF = fluence factor = $f^{(0.28 - 0.10*\log(f))}$.

(e) $RT_{NDT(U)}$ values are taken from Table 4.2.2-3.

(f) Per the guidance of Regulatory Guide 1.99, Revision 2, the base metal σ_Δ = 17°F for Position 1.1. Also, per Regulatory Guide 1.99, Revision 2, the weld metal σ_Δ = 28°F for Position 1.1. However, σ_Δ need not exceed 0.5*ΔRT_{NDT} for either forgings or welds with or without surveillance data.

Table 4.2.4-2 Calculation of the Unit 1 ART Values at the 1/4T Location for the Beltline Materials at 50.3 EFPY

Material	Heat Number	Flux Type (Lot)	R.G. 1.99, Rev. 2 Position	CF(b)	Surface Fluence(c) (x 10^{19} n/cm², E > 1.0 MeV)	1/4T Fluence(d) (x 10^{19} n/cm², E > 1.0 MeV)	1/4T FF(e)	$RT_{NDT(U)}$ (f) (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ (g) (°F)	M (°F)	ART (°F)
Upper Shell Forging 05	990286 / 295213	-	1.1	121.50	0.215	0.136	0.481	1	58.4	0.0	17.0	34.0	93.4
Upper to Intermediate Shell Circumferential Weld (OD 94%)	25295	SMIT 89 (1170)	1.1	163.25	0.248	0.156	0.512	-40	83.6	0.0	28.0	56.0	99.6
Using credible surveillance data(h)			2.1	150.69	0.248	0.156	0.512	-40	77.2	0.0	14.0	28.0	65.2
Upper to Intermediate Shell Circumferential Weld (ID 6%)(k)	4278	SMIT 89 (1211)	1.1	63.00	0.248	0.156	0.512	-4	32.3	0.0	16.1	32.3	60.6
Using non-credible surveillance data(i)			2.1	80.71	0.248	0.156	0.512	-4	41.3	0.0	20.7	41.3	78.7
Intermediate Shell Forging 04	990311 / 298244	-	1.1	86.00	5.03	3.17	1.304	-6	112.1	0.0	17.0	34.0	140.1
Intermediate to Lower Shell Circumferential Weld	25531	SMIT 89 (1211)	1.1	56.22	5.02	3.17	1.304	-2	73.3	0.0	28.0	56.0	127.3
Using non-credible surveillance data(j)			2.1	67.53	5.02	3.17	1.304	-2	88.0	0.0	28.0	56.0	142.0
Lower Shell Forging 03	990400 / 292332	-	1.1	119.97	5.13	3.24	1.309	33	157.0	0.0	17.0	34.0	224.0
Using non-credible surveillance data(j)			2.1	81.68	5.13	3.24	1.309	33	106.9	0.0	17.0	34.0	**173.9**

Notes:

(a) The Regulatory Guide 1.99, Revision 2 methodology was utilized in the calculation of the ART values.

(b) Chemistry factors are taken from Table 3-7 of WCAP-18364-NP.

(c) Fluence is taken from Table 4.2.1-1.

(d) The 1/4T fluence values were calculated from the surface fluence, the reactor vessel beltline thickness (7.677 inches), and equation $f = fsurf * e^{-0.24(x)}$ from Regulatory Guide 1.99, Revision 2, where x = the depth into the vessel wall (inches).

(e) FF = fluence factor = $f^{(0.28 - 0.10*\log(f))}$.

(f) $RT_{NDT(U)}$ values are taken from Table 4.2.2-3.

(g) Per the guidance of Regulatory Guide 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 σ_Δ = 8.5°F for Position 2.1 with credible surveillance data. Also, per Regulatory Guide 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 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 forgings or welds with or without surveillance data.

(h) The surveillance data for weld Heat # 25295 from the Sequoyah Unit 1 surveillance program were deemed credible per WCAP-17539-NP.

(i) The surveillance data for weld Heat # 4278 from the Sequoyah Unit 2 surveillance program were deemed non-credible per WCAP-17539-NP.

(j) The credibility evaluation for the Unit 1 surveillance data in Appendix A.1 of WCAP-18364-NP determined that the Lower Shell Forging 03 and weld Heat # 25531 surveillance data are deemed non-credible.

(k) Since this inner diameter (ID) weld is only 6% of the vessel thickness, the weld is not present at the 1/4T location; hence, it is not applicable to this calculation. It is presented for information only.

Table 4.2.4-3 Calculation of the Unit 2 Nozzle ART Values at the Surface Location for the Extended Beltline Materials at 52.3 EFPY

Material	Heat Number	Flux Type (Lot)	R.G. 1.99, Rev. 2 Position	CF(b)	Surface Fluence(c) (x 10^{19} n/cm^2, E > 1.0 MeV)	Surf. FF(d)	$RT_{NDT(U)}$(e) (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ (f) (°F)	M (°F)	ART (°F)
Inlet Nozzle Forging 09 to Upper Shell Weld	8816 20459 27622	LW320 (26 & 28)	1.1	163.20	0.00603	0	30(g)	0.0	0.0	0.0	0.0	30.0
Inlet Nozzle Forging 10 to Upper Shell Weld			1.1	163.20	0.0227	0.186	30(g)	30.3	0.0	15.2	30.3	90.7
Inlet Nozzle Forging 11 to Upper Shell Weld			1.1	163.20	0.00858	0	30(g)	0.0	0.0	0.0	0.0	30.0
Outlet Nozzle Forging 12 to Upper Shell Weld			1.1	163.20	0.0132	0.132	30(g)	21.5	0.0	10.8	21.5	73.1
Outlet Nozzle Forging 13 to Upper Shell Weld			1.1	163.20	0.00350	0	30(g)	0.0	0.0	0.0	0.0	30.0
Outlet Nozzle Forging 14 to Upper Shell Weld			1.1	163.20	0.00498	0	30(g)	0.0	0.0	0.0	0.0	30.0
Inlet Nozzle Forging 09	990426	-	1.1	150.40	0.00285	0	11	0.0	0.0	0.0	0.0	11.0
Inlet Nozzle Forging 10	54567-2	-	1.1	104.75	0.0107	0.115	5	12.0	0.0	6.0	12.0	29.0
Inlet Nozzle Forging 11	54590-2	-	1.1	118.25	0.00405	0	-31	0.0	0.0	0.0	0.0	-31.0
Outlet Nozzle Forging 12	990426-22	-	1.1	150.00	0.00633	0	8	0.0	0.0	0.0	0.0	8.0
Outlet Nozzle Forging 13	990426-31	-	1.1	149.60	0.00168	0	1	0.0	0.0	0.0	0.0	1.0
Outlet Nozzle Forging 14	791291	-	1.1	86.00	0.00239	0	-22	0.0	0.0	0.0	0.0	-22.0

Notes:

(a) The Regulatory Guide 1.99, Revision 2 methodology was utilized in the calculation of the ART values.

(b) Chemistry factors are taken from Table 3-8 of WCAP-18364-NP.

(c) Fluence is taken from Table 4.2.1-2. The fluence values for the nozzle forgings are taken at the postulated 1/4T flaw axial location. The fluence values for the inlet/outlet nozzle to upper shell welds are taken at the lowest extent of the nozzle weld centerline. Analysis of the nozzle forgings and associated welds are conservatively performed using the surface fluence, neglecting attenuation through the reactor vessel wall. Embrittlement effects are considered only if the fluence is greater than 10^{17} n/cm^2. For materials with fluence less than 10^{17} n/cm^2 the FF is set equal to 0.

(d) FF = fluence factor = $f^{(0.28 - 0.10*\log(f))}$.

(e) $RT_{NDT(U)}$ values are taken from Table 4.2.2-4.

(f) Per the guidance of Regulatory Guide 1.99, Revision 2, the base metal σ_Δ = 17°F for Position 1.1. Also, per Regulatory Guide 1.99, Revision 2, the weld metal σ_Δ = 28°F for Position 1.1. However, σ_Δ need not exceed 0.5*ΔRT_{NDT} for either forgings or welds with or without surveillance data.

(g) The $RT_{NDT(U)}$ is based on the highest $RT_{NDT(U)}$ of the heats associated with this weld.

Table 4.2.4-4 Calculation of the Unit 2 ART Values at the 1/4T Location for the Beltline Materials at 52.3 EFPY

Material	Heat Number	Flux Type (Lot)	R.G. 1.99, Rev. 2 Position	CF[b]	Surface Fluence[c] (x 10^{19} n/cm^2, E > 1.0 MeV)	1/4T Fluence[d] (x 10^{19} n/cm^2, E > 1.0 MeV	1/4T FF[e]	$RT_{NDT(U)}$[f] (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ (f) (°F)	M (°F)	ART (°F)
Upper Shell Forging 05	990598 / 291396	-	1.1	51.00	0.223	0.141	0.489	8	24.9	0.0	12.5	24.9	57.8
Upper to Intermediate Shell Circumferential Weld (OD 94%)	4278	SMIT 89 (1211)	1.1	63.00	0.258	0.163	0.521	-4	32.8	0.0	16.4	32.8	61.7
Using non-credible surveillance data[h]			2.1	80.71	0.258	0.163	0.521	-4	42.1	0.0	21.0	42.1	80.1
Upper to Intermediate Shell Circumferential Weld (ID 6%)[j]	801	SMIT 89 (1211)	1.1	87.80	0.258	0.163	0.521	10	45.8	0.0	22.9	45.8	101.5
Intermediate Shell Forging 04	990496 / 292424	-	1.1	74.00	5.25	3.31	1.314	69	97.2	0.0	17.0	34.0	200.2
Using non-credible surveillance data[i]			2.1	53.44	5.25	3.31	1.314	69	70.2	0.0	17.0	34.0	173.2
Intermediate to Lower Shell Circumferential Weld	716126	LW320 (26)	1.1	36.09	5.24	3.31	1.314	-67	47.4	0.0	23.7	47.4	27.8
Using credible surveillance data[i]			2.1	26.61	5.24	3.31	1.314	-67	35.0	0.0	14.0	28.0	-4.0
Lower Shell Forging 03	990533 / 297355	-	1.1	96.00	5.36	3.38	1.319	37	126.6	0.0	17.0	34.0	**197.6**

Notes:

(a) The Regulatory Guide 1.99, Revision 2 methodology was utilized in the calculation of the ART values.

(b) Chemistry factors are taken from Table 3-8 of WCAP-18364-NP.

(c) Fluence is taken from Table 4.2.1-2.

(d) The 1/4T fluence values were calculated from the surface fluence, the reactor vessel beltline thickness (7.677 inches), and equation $f = f_{surf} * e^{-0.24(x)}$ from Regulatory Guide 1.99, Revision 2, where x = the depth into the vessel wall (inches).

(e) FF = fluence factor = $f^{(0.28 - 0.10*\log(f))}$.

(f) $RT_{NDT(U)}$ values are taken from Table 4.2.2-4

(g) Per the guidance of Regulatory Guide 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 σ_{Δ} = 8.5°F for Position 2.1 with credible surveillance data. Also, per Regulatory Guide 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 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 forgings or welds with or without surveillance data.

(h) The surveillance data for weld Heat # 4278 from the Sequoyah Unit 2 surveillance program were deemed non-credible per WCAP-17539-NP.

(i) The credibility evaluation for the Unit 2 surveillance data in Appendix A.2 of WCAP-18364-NP determined that the Intermediate Shell Forging 04 surveillance data are deemed non-credible; however, the weld Heat # 716126 surveillance data are deemed credible.

(j) Since this inner diameter (ID) weld is only 6% of the vessel thickness, the weld is not present at the 1/4T location; hence, it is not applicable to this calculation. It is presented for information only.

Table 4.2.4-5 Calculation of the Unit 1 Nozzle ART Values at the Surface Location for the Extended Beltline Materials at 72 EFPY

Material	Heat Number	Flux Type (Lot)	R.G. 1.99, Rev. 2 Position	CF(b)	Surface Fluence(c) (x 10^{19} n/cm^2, E > 1.0 MeV)	Surf. FF(d)	$RT_{NDT(U)}$(e) (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ(f) (°F)	M (°F)	ART (°F)
Inlet Nozzle Forging 09 to Upper Shell Weld	Rotterdam	-	1.1	293.45	0.00898	0	30	0.0	0.0	0.0	0.0	30.0
Inlet Nozzle Forging 10 to Upper Shell Weld	Rotterdam	-	1.1	293.45	0.0313	0.225	30	66.1	0.0	28.0	56.0	152.1
Inlet Nozzle Forging 11 to Upper Shell Weld	Rotterdam	-	1.1	293.45	0.0120	0.124	30	36.4	0.0	18.2	36.4	102.7
Outlet Nozzle Forging 12 to Upper Shell Weld	Rotterdam	-	1.1	293.45	0.0182	0.162	30	47.6	0.0	23.8	47.6	125.2
Outlet Nozzle Forging 13 to Upper Shell Weld	Rotterdam	-	1.1	293.45	0.00522	0	30	0.0	0.0	0.0	0.0	30.0
Outlet Nozzle Forging 14 to Upper Shell Weld	Rotterdam	-	1.1	293.45	0.00697	0	30	0.0	0.0	0.0	0.0	30.0
Inlet Nozzle Forging 09	990290-11	-	1.1	96.00	0.00425	0	-14	0.0	0.0	0.0	0.0	-14.0
Inlet Nozzle Forging 10	990290-12	-	1.1	95.75	0.0148	0.142	-10	13.6	0.0	6.8	13.6	17.2
Inlet Nozzle Forging 11	990268-21	-	1.1	140.30	0.00568	0	8	0.0	0.0	0.0	0.0	8.0
Outlet Nozzle Forging 12	990290-31	-	1.1	96.00	0.00875	0	-6	0.0	0.0	0.0	0.0	-6.0
Outlet Nozzle Forging 13	990290-22	-	1.1	96.00	0.00251	0	-7	0.0	0.0	0.0	0.0	-7.0
Outlet Nozzle Forging 14	990290-21	-	1.1	96.00	0.00335	0	8	0.0	0.0	0.0	0.0	8.0

Notes:

(a) The Regulatory Guide 1.99, Revision 2 methodology was utilized in the calculation of the ART values.

(b) Chemistry factors are taken from Table 3-7 of WCAP-18364-NP.

(c) Fluence is taken from Table 4.2.1-1. The fluence values for the nozzle forgings are taken at the postulated 1/4T flaw axial location. The fluence values for the inlet/outlet nozzle to upper shell welds are taken at the lowest extent of the nozzle weld centerline. Analysis of the nozzle forgings and associated welds are conservatively performed using the surface fluence, neglecting attenuation through the reactor vessel wall. Embrittlement effects are considered only if the fluence is greater than 10^{17} n/cm^2. For materials with fluence less than 10^{17} n/cm^2 the FF is set equal to 0.

(d) FF = fluence factor = $f^{(0.28 - 0.10*\log(f))}$.

(e) $RT_{NDT(U)}$ values are taken from Table 4.2.2-3.

(f) Per the guidance of Regulatory Guide 1.99, Revision 2, the base metal σ_Δ = 17°F for Position 1.1. Also, per Regulatory Guide 1.99, Revision 2, the weld metal σ_Δ = 28°F for Position 1.1. However, σ_Δ need not exceed $0.5*\Delta RT_{NDT}$ for either forgings or welds with or without surveillance data.

Table 4.2.4-6 Calculation of the Unit 1 ART Values at the 1/4T Location for the Beltline Materials at 72 EFPY

Material	Heat Number	Flux Type (Lot)	R.G. 1.99, Rev. 2 Position	CF[b]	Surface Fluence[c] (x 10^{19} n/cm^2, E > 1.0 MeV)	1/4T Fluence[d] (x 10^{19} n/cm^2, E > 1.0 MeV)	1/4T FF[e]	$RT_{NDT(U)}$[f] (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ[g] (°F)	M (°F)	ART (°F)
Upper Shell Forging 05	990286 / 295213	-	1.1	121.5	0.304	0.192	0.559	1	68.0	0.0	17.0	34.0	103.0
Upper to Intermediate Shell Circumferential Weld (OD 94%)	25295	SMIT 89 (1170)	1.1	163.25	0.351	0.221	0.594	-40	97.0	0.0	28.0	56.0	113.0
Using credible surveillance data[h]			2.1	150.69	0.351	0.221	0.594	-40	89.5	0.0	14.0	28.0	77.5
Upper to Intermediate Shell Circumferential Weld (ID 6%)[k]	4278	SMIT 89 (1211)	1.1	63.00	0.351	0.221	0.594	-4	37.4	0.0	18.7	37.4	70.8
Using non-credible surveillance data[i]			2.1	80.71	0.351	0.221	0.594	-4	47.9	0.0	24.0	47.9	91.9
Intermediate Shell Forging 04	990311 / 298244	-	1.1	86.00	7.07	4.46	1.379	-6	118.6	0.0	17.0	34.0	146.6
Intermediate to Lower Shell Circumferential Weld	25531	SMIT 89 (1211)	1.1	56.22	7.04	4.44	1.378	-2	77.5	0.0	28.0	56.0	131.5
Using non-credible surveillance data[j]			2.1	67.53	7.04	4.44	1.378	-2	93.1	0.0	28.0	56.0	147.1
Lower Shell Forging 03	990400 / 292332	-	1.1	119.97	7.20	4.54	1.383	33	165.9	0.0	17.0	34.0	232.9
Using non-credible surveillance data[j]			2.1	81.68	7.20	4.54	1.383	33	113.0	0.0	17.0	34.0	**180.0**

Notes:

(a) Chemical composition data taken from Table 4.2.1-1 and Table 4.2.2-2. Chemistry factor values taken from Table 3-10 of WCAP-18242-NP.

(b) The Regulatory Guide 1.99, Revision 2 methodology was utilized in the calculation of the ART values.

(c) Chemistry factors are taken from Table 3-7 of WCAP-18364-NP.

(d) Fluence is taken from Table 4.2.1-1.

(e) The 1/4T fluence values were calculated from the surface fluence, the reactor vessel beltline thickness (7.677 inches), and equation $f = f_{surf} * e^{-0.24(x)}$ from Regulatory Guide 1.99, Revision 2, where x = the depth into the vessel wall (inches).

(f) FF = fluence factor = $f^{(0.28 - 0.10*\log (f))}$.

(g) $RT_{NDT(U)}$ values are taken from Table 4.2.2-3.

(h) Per the guidance of Regulatory Guide 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 σ_Δ = 8.5°F for Position 2.1 with credible surveillance data. Also, per Regulatory Guide 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 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 forgings or welds with or without surveillance data.

(i) The surveillance data for weld Heat # 25295 from the Sequoyah Unit 1 surveillance program were deemed credible per WCAP-17539-NP.

(j) The surveillance data for weld Heat # 4278 from the Sequoyah Unit 2 surveillance program were deemed non-credible per WCAP-17539-NP.

(k) The credibility evaluation for the Unit 1 surveillance data in Appendix A.1 of WCAP-18364-NP determined that the Lower Shell Forging 03 and weld Heat # 25531 surveillance data are deemed non-credible.

(l) Since this inner diameter (ID) weld is only 6% of the vessel thickness, the weld is not present at the 1/4T location; hence, it is not applicable to this calculation. It is presented for information only.

Table 4.2.4-7 Calculation of the Unit 2 ART Nozzle Values at the Surface Location for the Extended Beltline Materials at 72 EFPY

Material	Heat Number	Flux Type (Lot)	R.G. 1.99, Rev. 2 Position	CF[b]	Surface Fluence[c] (x 10^{19} n/cm^2, E > 1.0 MeV)	Surface FF[d]	$RT_{NDT(U)}$[e] (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ[f] (°F)	M (°F)	ART (°F)
Inlet Nozzle Forging 09 to Upper Shell Weld	8816 20459 27622	LW320 (26 & 28)	1.1	163.20	0.00826	0	30[g]	0.0	0.0	0.0	0.0	30.0
Inlet Nozzle Forging 10 to Upper Shell Weld			1.1	163.20	0.0314	0.226	30[g]	36.8	0.0	18.4	36.8	103.6
Inlet Nozzle Forging 11 to Upper Shell Weld			1.1	163.20	0.0118	0.123	30[g]	20.0	0.0	10.0	20.0	70.0
Inlet Nozzle Forging 12 to Upper Shell Weld			1.1	163.20	0.0182	0.162	30[g]	26.5	0.0	13.2	26.5	82.9
Inlet Nozzle Forging 13 to Upper Shell Weld			1.1	163.20	0.00479	0	30[g]	0.0	0.0	0.0	0.0	30.0
Inlet Nozzle Forging 14 to Upper Shell Weld			1.1	163.20	0.00687	0	30[g]	0.0	0.0	0.0	0.0	30.0
Inlet Nozzle Forging 09	990426	-	1.1	150.40	0.00390	0	11	0.0	0.0	0.0	0.0	11.0
Inlet Nozzle Forging 10	54567-2	-	1.1	104.75	0.0148	0.142	5	14.9	0.0	7.4	14.9	34.8
Inlet Nozzle Forging 11	54590-2	-	1.1	118.25	0.00559	0	-31	0.0	0.0	0.0	0.0	-31.0
Outlet Nozzle Forging 12	990426-22	-	1.1	150.00	0.00875	0	8	0.0	0.0	0.0	0.0	8.0
Outlet Nozzle Forging 13	220426-31	-	1.1	149.60	0.00230	0	1	0.0	0.0	0.0	0.0	1.0
Outlet Nozzle Forging 14	791291	-	1.1	86.00	0.00330	0	-22	0.0	0.0	0.0	0.0	-22.0

Notes:

(a) The Regulatory Guide 1.99, Revision 2 methodology was utilized in the calculation of the ART values.

(b) Chemistry factors are taken from Table 3-8 of WCAP-18364-NP.

(c) Fluence is taken from Table 4.2.1-2. The fluence values for the nozzle forgings are taken at the postulated 1/4T flaw axial location. The fluence values for the inlet/outlet nozzle to upper shell welds are taken at the lowest extent of the nozzle weld centerline. Analysis of the nozzle forgings and associated welds are conservatively performed using the surface fluence, neglecting attenuation through the reactor vessel wall. Embrittlement effects are considered only if the fluence is greater than 10^{17} n/cm^2. For materials with fluence less than 10^{17} n/cm^2 the FF is set equal to 0.

(d) FF = fluence factor = $f^{(0.28 - 0.10*\log (f))}$.

(e) $RT_{NDT(U)}$ values are taken from Table 4.2.2-4.

(f) Per the guidance of Regulatory Guide 1.99, Revision 2, the base metal σ_{Δ} = 17°F for Position 1.1. Also, per Regulatory Guide 1.99, Revision 2, the weld metal σ_{Δ} = 28°F for Position 1.1. However, σ_{Δ} need not exceed 0.5*ΔRT_{NDT} for either forgings or welds with or without surveillance data.

(g) The $RT_{NDT(U)}$ is based on the highest $RT_{NDT(U)}$ of the heats associated with this weld.

Table 4.2.4-8 Calculation of the Unit 2 ART Values at the 1/4T Location for the Beltline Materials at 72 EFPY

Material	Heat Number	Flux Type (Lot)	R.G. 1.99, Rev. 2 Position	CF(b)	Surface Fluence(c) (x 10^{19} n/cm^2, E > 1.0 MeV)	1/4T Fluence(d) (x 10^{19} n/cm^2, E > 1.0 MeV	1/4T FF(e)	$RT_{NDT(U)}$(f) (°F)	Predicted ΔRT_{NDT} (°F)	σ_I (°F)	σ_Δ (g) (°F)	M (°F)	ART (°F)
Upper Shell Forging 05	990598 / 291396	-	1.1	51.00	0.307	0.194	0.562	8	28.7	0.0	14.3	28.7	65.3
Upper to Intermediate Shell Circumferential Weld (OD 94%)	4278	SMIT 89 (1211)	1.1	63.00	0.355	0.224	0.597	-4	37.6	0.0	18.8	37.6	71.2
Using non-credible surveillance data(h)			2.1	80.71	0.355	0.224	0.597	-4	48.2	0.0	24.1	48.2	92.3
Upper to Intermediate Shell Circumferential Weld (ID 6%)(j)	801	SMIT 89 (1211)	1.1	87.80	0.355	0.224	0.597	10	52.4	0.0	26.2	52.4	114.8
Intermediate Shell Forging 04	990496 / 292424	-	1.1	74.00	7.20	4.54	1.383	69	102.3	0.0	17.0	34.0	205.3
Using non-credible surveillance data(i)			2.1	53.44	7.20	4.54	1.383	69	73.9	0.0	17.0	34.0	176.9
Intermediate to Lower Shell Circumferential Weld	716126	LW320 (26)	1.1	36.09	7.18	4.53	1.382	-67	49.9	0.0	24.9	49.9	32.8
Using credible surveillance data(i)			2.1	26.61	7.18	4.53	1.382	-67	36.8	0.0	14.0	28.0	-2.2
Lower Shell Forging 03	990533 / 297355	-	1.1	96.00	7.34	4.63	1.387	37	133.2	0.0	17.0	34.0	**204.2**

Notes:

(a) The Regulatory Guide 1.99, Revision 2 methodology was utilized in the calculation of the ART values.

(b) Chemistry factors are taken from Table 3-8 of WCAP-18364-NP.

(c) Fluence is taken from Table 4.2.1-2.

(d) The 1/4T fluence values were calculated from the surface fluence, the reactor vessel beltline thickness (7.677 inches), and equation $f = f_{surf} * e^{-0.24(x)}$ from Regulatory Guide 1.99, Revision 2, where x = the depth into the vessel wall (inches).

(e) FF = fluence factor = $f^{(0.28 - 0.10*\log(f))}$.

(f) $RT_{NDT(U)}$ values are taken from Table 4.2.2-4.

(g) Per the guidance of Regulatory Guide 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 σ_Δ = 8.5°F for Position 2.1 with credible surveillance data. Also, per Regulatory Guide 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 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 forgings or welds with or without surveillance data.

(h) The surveillance data for weld Heat # 4278 from the Sequoyah Unit 2 surveillance program were deemed non-credible per WCAP-17539-NP.

(i) The credibility evaluation for the Unit 2 surveillance data in Appendix A.2 of WCAP-18364-NP determined that the Intermediate Shell Forging 04 surveillance data are deemed non-credible; however, the weld Heat # 716126 surveillance data are deemed credible.

(j) Since this inner diameter (ID) weld is only 6% of the vessel thickness, the weld is not present at the 1/4T location; hence, it is not applicable to this calculation. It is presented for information only.

Table 4.2.4-9 Summary of the Units 1 and 2 Limiting ART Values Used in the Applicability Evaluation of the Reactor Pressure Vessel Heatup and Cooldown Curves

	1/4T Location	3/4T Location
ART in Current Technical Specifications (°F)	218.5	195.6
	Limiting Material: Unit 2 Lower Shell Forging 03 (developed using Position 1.1 data)	
Unit 1 Limiting ART at 72 EFPY (°F)	180.0	162.0
	Limiting Material: Unit 1 Lower Shell Forging 03 (developed using Position 2.1 with non-credible surveillance data and full margin term)	
Unit 2 Limiting ART at 72 EFPY (°F)	204.2	183.1
	Limiting Material: Unit 2 Lower Shell Forging 03 (developed using Position 1.1 data)	

4.2.5 PRESSURE-TEMPERATURE LIMITS

TLAA Description:

10 CFR 50, Appendix G, requires that the RV 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 RV is exposed to increased neutron irradiation, its fracture toughness is reduced. The P-T limits must account for the anticipated RV fluence.

The current P-T limits are based upon fluence projections for 60 years of plant operation. Therefore, the P-T limits analyses meet the definition of 10 CFR 54.3(a) (Reference 1.7-2) and have been identified as TLAAs.

TLAA Evaluation:

Heatup and cooldown limit curves are calculated using the most limiting value of RT_{NDT} corresponding to the limiting material in the beltline region of the RV. The most limiting RT_{NDT} of the material in the core region (beltline) of the RV is determined by using the unirradiated RV material fracture toughness properties and estimating the irradiation induced shift (ΔRT_{NDT}).

RT_{NDT} increases as the material is exposed to fast neutron irradiation; therefore, to find the most limiting core region (beltline) RT_{NDT} at any time, ΔRT_{NDT} due to the neutron radiation exposure associated with that time must be added to the original unirradiated RT_{NDT}. Using the ART values, P-T limit curves are determined in accordance with the requirements of 10 CFR 50, Appendix G, as augmented by ASME Code, Section XI, Appendix G.

The P-T limits for 50.3 EFPY for Unit 1, and 52.3 EFPY for Unit 2, (currently maintained in the Technical Specifications for Units 1 and 2) are based on the latest fluence data.

According to NUREG-2192, Section 4.2.2.1.4, the P-T limits for the subsequent period of extended operation 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 current licensing basis will ensure that the P-T limits for the subsequent period of extended operation will be updated prior to exceeding the EFPY for which they remain valid.

Nozzle materials were evaluated in WCAP-18364-NP at 50.3 EFPY for Unit 1, and 52.3 EFPY for Unit 2, and 72 EFPY for both units. The nozzle forging materials evaluated are documented in Tables 4.2.4-1, 4.2.4-3, 4.2.4-5, and 4.2.4-7. All nozzle materials were assigned the fluence values at the postulated 1/4T flaw location for each specific nozzle in Tables 4.2.1-1 and 4.2.1-2. Thus, Unit 1 Inlet Nozzle 10 and Unit 2 Inlet Nozzle 10 have neutron fluence values greater than 1.0×10^{17} n/cm^2 (E > 1.0 MeV) at 72 EFPY. In order to fully assess the Units 1 and 2 P-T limit curves applicability to 72 EFPY, a nozzle corner fracture mechanics analysis was completed for all nozzle materials.

These nozzle P-T limit curves were generated and compared to the beltline P-T limit curves to ensure that the beltline curves are bounding. The detailed nozzle forging fracture mechanics evaluation and comparison to the applicable RV beltline P-T limit curves are documented in WCAP-18363-NP. The current beltline curves were confirmed to remain more limiting than the nozzle curves through 72 EFPY.

The development of the 50.3 EFPY for Unit 1, and 52.3 EFPY for Unit 2, P-T limit curves for normal heatup and cooldown of the primary reactor coolant system for Units 1 and 2 was documented in WCAP-15112. The P-T limit curves developed for 72 EFPY in WCAP-18363-NP are based on the K_{Ic} methodology and the limiting beltline material ART values, which are influenced by both the fluence and the initial material properties of that material. The Units 1 and 2 P-T limit curves were developed by calculating ART values utilizing the vessel fluence at the clad/base metal interface corresponding to each RV material. Since the development of the current curves, the fluence values and initial material properties used to calculate ART values have been updated.

The K_{Ic} methodology was used to confirm the applicability of the P-T limit curves developed based on WCAP-15112. In order to be able to use the existing P-T curves through the subsequent period of extended operation, the limiting RV material ART values with consideration of the updated 72 EFPY fluence values, revised Position 2.1 chemistry factor values, and updated initial RT_{NDT} values must be shown to be less than or equal to the limiting beltline material ART values used in development of the P-T limit curves contained in WCAP-15112 and the Units 1 and 2 Technical Specifications. The Regulatory Guide 1.99, Revision 2 methodology was used along with the surface fluence of Section 2 of WCAP-18364-NP to calculate ART values for the Units 1 and 2 RV materials at 50.3 EFPY for Unit 1, 52.3 EFPY for Unit 2, and 72 EFPY for both units.

The comparisons of the limiting ART values calculated as part of this RV integrity TLAA evaluation, using updated fluence and initial material properties, to those used in calculation of the existing P-T limit curves are contained in Table 4.2.4-9 for Units 1 and 2. With the consideration of TLAA fluence projections, the applicability of the P-T limit curves in WCAP-15112 may be extended to 72 EFPY for the Units 1 and 2 cylindrical shell materials. Nozzle P-T limit curves were developed per WCAP-18363-NP and compared to the cylindrical shell beltline curves. Per WCAP-18363-NP, the applicability of the P-T limit curves may be extended through the subsequent period of extended operation, because the current Technical Specifications P-T limit curves bound the new P-T limit curves developed in WCAP-18363-NP.

In addition, the applicable RV flange and closure head initial RT_{NDT} values are bounding and the P-T limit curves flange notch requires no change or further consideration. Finally, the lowest service temperature requirements are not applicable to Units 1 and 2, because the plants are Westinghouse-designed per ASME Code, Section III, and utilize stainless steel reactor coolant system piping.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

Since the P-T limits will be updated through the 10 CFR 50.90 process at a later, appropriate date, the effects of aging on the intended function(s) of the RVs will be adequately managed for the subsequent period of extended operation. The *Reactor Vessel Material Surveillance* program (B2.1.19) and plant Technical Specifications will ensure that updated P-T limits based upon updated ART values will be submitted to the NRC for approval prior to exceeding the period of applicability for Units 1 and 2.

4.2.6 LOW TEMPERATURE OVERPRESSURE PROTECTION

TLAA Description:

Low temperature overpressure protection (LTOP) system (sometimes referred to as the Reactor Coolant System Overpressure Mitigating System, or the RV Overpressure Mitigating System) at Units 1 and 2 is required by Technical Specification Limited Condition for Operation 3.4.12. Two pressurizer power operated relief valves (PORV) provide the automatic relief capability during the design basis mass input and the design basis heat input transients to automatically prevent the reactor coolant system pressure from exceeding the P-T limit curves based on 10 CFR 50, Appendix G.

LTOP system setpoints are based on the P-T limits calculation which is a TLAA.

TLAA Evaluation:

In WCAP-18363-NP the maximum allowable LTOP system Power Operated Relief Valve (PORV) setpoint was calculated to be ≤ 400 psig when any RCS cold leg temperature is ≤ 180°F and ≤ 558 psig when any RCS cold leg temperature is ≤ 280°F for Units 1 and 2 through the subsequent period of extended operation. The calculation was performed in accordance with the WCAP-14040-A methodology using critical LTOP system input parameters, updated results of the design basis mass injection and heat injection transients, and the limiting axial flaw steady state ASME Code, Section XI, Appendix G limits from WCAP-15112 that were determined to be applicable through 72 EFPY for Units 1 and 2.

The evaluation showed that the current Technical Specifications value of ≤ 375 psig when any RCS cold leg temperature is ≤ 180°F and ≤ 540 psig when any RCS cold leg temperature is ≤ 280°F maintain margin to the maximum allowable settings calculated for the subsequent period of extended operation throughout the range of LTOP applicability. Therefore, the current LTOP system settings are bounding and can be maintained through 72 EFPY for Units 1 and 2.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The LTOP system setpoint and enabling temperature have been projected to the end of the subsequent period of extended operation.

4.3 METAL FATIGUE

Fatigue analyses are required on 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) B31.7, "Nuclear Power Piping" (Reference 4.8-26) Class 1; USAS (ANSI) B31.1, "Power Piping" (Reference 4.8-27); as allowed per USAS (ANSI) B31.7, Class 2 and 3; and ASME Code, Section VIII, "Rules for Construction of Pressure Vessels"(Reference 4.8-28), Division 2; may require fatigue analysis or assume a stated number of full-range thermal and displacement transient cycles. NUREG-2192 also provides examples of components likely to have fatigue TLAAs within the 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 TLAAs within the current licensing basis for Units 1 and 2. Each potential fatigue TLAA was evaluated against the six elements of the TLAA definition specified in 10 CFR 54.3(a). Those that were identified as fatigue TLAAs are described in WCAP-18503-NP, "Resolution of North Anna Power Station Units 1 & 2 Time-Limited Aging Analyses for Subsequent License Renewal" (Reference 4.8-29) and evaluated in the following subsections:

- Transient Cycle Projections for 80 years (Section 4.3.1)
- ASME Code, Section III, Class 1 Fatigue Analyses (Section 4.3.2)
- USAS (ANSI) B31.1 Allowable Stress Analyses (Section 4.3.3)
- Environmentally-Assisted Fatigue (Section 4.3.4)
- Reactor Vessel Internals Fatigue Analyses (Section 4.3.5)
- High Energy Line Break Analyses (Section 4.3.6)

Since initial license renewal, major plant changes have consisted of measurement uncertainty recapture (MUR) power uprate; replacement RV closure heads (RRVCH); preemptive full structural weld overlays (SWOL) on pressurizer surge, safety, relief and spray nozzles; Unit 1 steam generator inlet nozzle (hot leg) SWOL; Unit 2 Upflow Conversion; 17 x 17 Robust Fuel Assembly Transition Reload; and Core Exit Thermocouple Nozzle Assembly (CETNA) project. Potential impacts on fatigue usage are discussed further in the following sections, as applicable.

4.3.1 TRANSIENT CYCLE PROJECTIONS FOR 80 YEARS

Fatigue analyses are based upon numbers and amplitudes of thermal and pressure transients. UFSAR, Table 5.2-4 and Section 18.4.2 list design transients and associated design cycles for Units 1 and 2. The intent of the design basis transient definitions is to bound a wide range of possible events with varying ranges of severity in temperature and pressure. Current licensing basis fatigue analyses are based upon the original number of design cycles (40 years) and are postulated to bound 60 years of service life. Since the fatigue analyses are based upon a number of cycles postulated to bound 60 years of service, these fatigue analyses are considered TLAAs and require disposition for the subsequent period of extended operation. The transient cycle projections for 80 years for Units 1 and 2 are documented in WCAP-18503-NP.

A review of *Fatigue Monitoring* program (B3.1) data was performed to identify the number of cumulative cycles for each transient type that occurred at Units 1 and 2 up to November 8, 2017. Baseline cycle counts were projected to an 80-year operating life based on the actual accumulation history over the last 10 years (November 8, 2007 - November 8, 2017). They do not represent a revision of the design basis. These transient cycles and projections are shown in Table 4.3.1-1, “80-year Transient Cycle Projections.” Since most nuclear plants, including Units 1 and 2, have experienced a significant declining trend in accumulation of transients over time, transient projections based on recent operating experience provide an appropriate basis for future projections. Therefore, each monitored design transient was evaluated to determine if the recent 10-year trend had a consistent cycle accumulation rate. The 10-year rate cycle projection method was used to extrapolate the projected number of future occurrences beginning November 8, 2017 and ending at 80 years of plant operation. The end of the 80-year life is April 1, 2058 for Unit 1, and August 21, 2060 for Unit 2.

As shown in Table 4.3.1-1, the 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 fatigue analyses. That is, 40 years of design cycles bound the 80-year projected cycles. The basis for assessing and projecting design transient cycles to the end of the subsequent period of extended operation is not a TLAA because the basis does not involve assessment of an applicable aging effect and does not meet criterion 2 for defining TLAAs in 10 CFR 54.3(a). The evaluation of fatigue is a TLAA for those major components and piping exposed to reactor coolant in the Reactor Vessel, RV Internals, and the Reactor Coolant System pressure boundary. Therefore, the fatigue analysis for Safety Class 1 components remain valid for the subsequent period of extended operation. In order to ensure the design cycles remain bounding in the Class 1 component fatigue analyses, the *Fatigue Monitoring* program (B3.1) will track cycles for significant fatigue transients listed in Table 4.3.1-1 and ensure corrective action is taken prior to potentially exceeding fatigue design limits. A Condition Report will be initiated based upon an administrative limit of 90% of the fatigue cycles.

Table 4.3.1-1 80-Year Transient Cycle Projections

Transients (UFSAR, Table 5.2-4 and Section 18.4.2)	Unit 1		Unit 2		CLB Cycles (40 year design cycles)
	Accrued Transient Cycles (11/8/2017)	80-Year Projected Transient Cycles	Accrued Transient Cycles (11/8/2017)	80-Year Projected Transient Cycles	
Normal Conditions					
Heatup at 100°F/hr(1)	58	99	55	113	200
Cooldown at 100°F/hr(2), (3)	57	98	54	112	200
Unit Loading at 5% of Full Power/min	Not Monitored(10)	432	Not Monitored(10)	471	18,300
Unit Unloading at 5% of Full Power/min	Not Monitored(10)	410	Not Monitored(10)	412	18,300
Step-Load Increase of 10% Full Power	6	8	6	8	2,000
Step-Load Decrease of 10% Full Power	6	8	6	8	2,000
Large step-load decrease	5	7	5	7	200
Steady-state Fluctuations	Not Monitored(10)	Infinite(13)	Not Monitored(10)	Infinite(13)	Infinite
Upset Conditions					
Loss of Load(4)	0	2	0	2	80
Loss of Power(5)	3	8	3	8	40
Loss of flow (partial loss of flow one pump only)(6)	1	3	3	8	80
Reactor trip from full power(7)	48	67	49	90	400
Inadvertent auxiliary pressurizer spray(8)	1	6	0	2	10
Faulted Conditions(9)					
Main reactor coolant pump pipe break	Not Monitored(11)	-	Not Monitored(11)	-	1
Steam pipe break	Not Monitored(11)	-	Not Monitored(11)	-	1
Design-basis earthquake	Not Monitored(11)	-	Not Monitored(11)	-	1
Test Conditions					
Turbine roll test	Not Monitored(12)	-	Not Monitored(12)	-	10

Transients (UFSAR, Table 5.2-4 and Section 18.4.2)	**Unit 1**		**Unit 2**		**CLB Cycles (40 year design cycles)**
	Accrued Transient Cycles (11/8/2017)	**80-Year Projected Transient Cycles**	**Accrued Transient Cycles (11/8/2017)**	**80-Year Projected Transient Cycles**	
Primary Side Hydrostatic Test	Not Monitored(12)	-	Not Monitored(12)	-	5
Secondary Side Hydrostatic Test	Not Monitored(12)	-	Not Monitored(12)	-	5
Primary-side leak test	Not Monitored(12)	-	Not Monitored(12)	-	50

Notes:

1. Heatup cycle - T_{avg} from < 200°F to > 550°F.
2. Cooldown cycle - T_{avg} from > 550°F to < 200°F.
3. Pressurizer cooldown at 200°F/hr from > 650°F to < 200°F is limited to 200 cycles and is included in the Cycle Counting Procedure.
4. Loss of load, without immediate turbine or reactor trip, > 15% of Rated Thermal Power to 0% of Rated Thermal Power.
5. Blackout with natural circulation in the reactor coolant system. Loss of offsite AC electrical power source supplying onsite engineered safety features (ESF) Electrical System.
6. Loss of only one reactor coolant pump.
7. 100% to 0% of Rated Thermal Power (Full Power Trip). Reactor trips that occur at greater than 25% power are being counted in the Cycle Counting Procedure. Reactor trips below 25% power were concluded to be insignificant to fatigue in Appendix B of CN-SDA-II-18-007 (Reference 4.8-30).
8. Spray water temperature differential > 320°F.
9. In accordance with the ASME Nuclear Power Plant Components Code, faulted conditions are not included in fatigue evaluations.
10. CLB cycles are > 20 times the projected cycles.
11. Faulted condition transients will be evaluated under the Corrective Action Program if one ever occurs.
12. There are no cycles projected cycles since there are no plans to perform any of these test conditions.
13. The steady-state fluctuation transients were determined to be insignificant to fatigue per Appendix B of CN-SDA-II-18-007 so an infinite number of cycles are specified.

Major changes since initial license renewal include process changes and replacement/additions to portions of the reactor coolant system.

The process changes that have occurred since initial license renewal are MUR power uprate, Unit 2 Upflow Conversion, and 17 x 17 Robust Fuel Assembly Transition Reload.

- NRC SER for the MUR power uprate (Reference 4.8-31) indicates no additional transients have been proposed as a result of MUR at Units 1 and 2.
- No transient definitions or cycles were updated for Unit 2 Upflow Conversion project.
- No transient definitions or cycles were updated for the 17 x 17 Fuel Reload Transition project.

The major modifications to the reactor coolant pressure boundary are the Replacement Reactor Vessel Closure Heads (RRVCH), Core Exit Thermocouple Nozzle Assembly (CETNA), FSWOL on pressurizer nozzle locations for Units 1 and 2, and Unit 1 steam generator inlet nozzle SWOL.

- The replacement RV closure heads (RRVCH) for each unit were fabricated by Framatome and installed during the early 2000s (2003 for Unit 2 and 2004 for Unit 1) using the original design basis transients.
- No transient definitions or cycles were updated for the CETNA project.
- All pressurizer safety, relief, spray and surge nozzle FSWOL installed in 2007 for both Units 1 and 2 had implicit fatigue evaluations using the original design basis transients [for operation from installation in 2007 through end of initial license renewal of 60 years] and is considered fatigue-related TLAA.
- The three-steam generator inlet nozzle SWOL at Unit 1 installed in 2012 had implicit fatigue evaluations using the original design basis transients and are qualified for the original design of 40 years of cyclic operation and is considered fatigue-related TLAA.

Therefore, the effects of fatigue on the intended function(s) of Safety Class 1 components will be adequately managed by the *Fatigue Monitoring* program (B3.1) during subsequent of extended operation.

4.3.2 ASME CODE, SECTION III, CLASS 1 FATIGUE ANALYSES

TLAA Description:

Fatigue analyses are performed per ASME Code, Section III. Each analysis must demonstrate that the cumulative usage factor (CUF) for the component will not exceed the ASME Code, Section III design limit of 1.0 when the component is exposed to all postulated transients.

The following Safety Class 1 components and fatigue waivers have been assessed for impact on fatigue in WCAP-18503-P, "Resolution of North Anna Power Station Units 1 & 2 Time-Limited Aging Analyses for Subsequent License Renewal:" (Reference 4.8-32)

- Control Rod Drive Mechanism (Section 4.3.2.1)
- Pressurizer (including Nozzle FSWOLs) (Section 4.3.2.2)
- Reactor Coolant Pump (Section 4.3.2.3)
- Reactor Vessel (Section 4.3.2.4)
- Steam Generators (including Unit 1 Inlet Nozzle SWOL) (Section 4.3.2.5)
- Pressurizer Surge Line (Section 4.3.2.6)
- Class 1 USAS (ANSI) B31.7 Piping (Section 4.3.2.7)
- Loop Stop Isolation Valves (Section 4.3.2.8)
- ASME Code, Section III, Class 1 Component Fatigue Waivers (Section 4.3.2.9)

4.3.2.1 Control Rod Drive Mechanism

TLAA Description:

The original reactor vessel closure heads (RVCH) have been replaced with closure heads fabricated by Framatome ANP for each Unit 1 and Unit 2. The existing CRDMs were reused on the replacement RVCHs and the fatigue evaluations of the pressure retaining portions of the CRDMs were performed to the requirements of the ASME Code, Section III. Fatigue analyses that consider transient cycles that occur over the life of the plant constitute TLAAs. The analysis of record (AOR) fatigue CUF results for the CRDM locations are less than 1.0.

TLAA Evaluation:

Following the identification of TLAAs for initial license renewal, there were four projects which could have potentially affected the transients in the CRDM design bases. These projects included the Unit 2 Upflow Conversion, the 17 x 17 Robust Fuel Assembly Fuel Transition Reload, the replacement RVCH, and the 2% MUR power uprate project.

As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) are postulated to bound 80 years of plant operations. The CUF values will remain less than unity for the fatigue analyses of record during the subsequent period of extended operation. Therefore, the fatigue analyses for the CRDM components remain valid for the subsequent period of extended operation. In order to ensure the design cycles remain bounding in the CRDM component fatigue analyses, the *Fatigue Monitoring* program (B3.1) will track cycles for significant fatigue transients listed in Table 4.3.1-1 and ensure corrective action is taken prior to potentially exceeding fatigue design limits.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of fatigue on the intended function(s) of CRDM components will be adequately managed by the *Fatigue Monitoring* program (B3.1) for the subsequent period of extended operation.

4.3.2.2 Pressurizer - (including Nozzle FSWOLs)

TLAA Description:

Units 1 and 2 each have a 1,400 ft^3 internal volume, vertical cylindrical pressurizer with hemispherical top and bottom heads to maintain system pressure during operation and limits pressure transients. During a change in plant loading, reactor coolant volume changes are accommodated in the pressurizer via the surge line. The fatigue evaluations of the pressurizer were performed to the requirements of ASME Code, Section III. Fatigue analyses that consider transient cycles that occur over the life of the plant constitute TLAAs.

In order to prevent loss of pressure boundary function as a result of primary water stress corrosion Cracking (PWSCC) and to ensure structural integrity of the pressurizer nozzle to pipe connections, preemptive FSWOLs were performed by Framatome on the pressurizer surge line, spray line, and safety and relief lines nozzles at Unit 1 and Unit 2 in 2007. There are fatigue TLAAs associated with these FSWOLs.

Thermal stratification was identified in NRC Bulletin 88-11, “Pressurizer Surge Line Thermal Stratification” (Reference 4.8-33) and is discussed in Section 4.3.2.6, Pressurizer Surge Line. Westinghouse has identified insurge/outsurge events, which imposed thermal loads not considered in the original design analyses and the evaluation of the surge lines is discussed in Section 4.3.4, Environmentally-Assisted Fatigue.

TLAA Evaluation:

There were two projects that could have potentially affected the transients in the pressurizer design basis since the identification of TLAAs for initial license renewal. These projects included the MUR power uprate, discussed above, and the FSWOLs applied to the safety, relief and spray nozzles on the top of the pressurizer, and the surge nozzle on the bottom of the pressurizer. Design-basis CUF values have been established for the newly installed FSWOLs on the pressurizer nozzles.

For the pressurizer, the MUR power uprate resulted in two areas of consideration. The general structural evaluation used power uprate loads and had no impact to the transient design cycle counts. Also evaluated in WCAP-15607-P, Addendum 4 “Evaluation of Pressurizer Insurge/Outsurge Transients for North Ana Subsequent License Renewal,” and Addendum 5 “Evaluation of Pressurizer Insurge/Outsurge Transients for North Anna Subsequent License Renewal-Environmentally Assisted Fatigue,” (References 4.8-34 and 4.8-35) was the impact of the revised NSSS operating parameters on the pressurizer insurge/outsurge transients, and their effect, in turn, on the integrity of the lower head and surge nozzle regions. The AOR fatigue CUF results are less than 1.0 as documented in WCAP-18503-P.

As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) are postulated to bound 80 years of plant operations. The CUF values will remain less than unity for the fatigue analyses of record during the subsequent period of extended operation. Therefore, the fatigue analyses for the pressurizer components remain valid for the subsequent period of extended operation. In order to ensure the design cycles remain bounding in the pressurizer component fatigue analyses, the *Fatigue Monitoring* program (B3.1) will track cycles for significant fatigue transients listed in Table 4.3.1-1 and ensure corrective action is taken prior to potentially exceeding fatigue design limits.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of fatigue on the intended function(s) of the pressurizer components will be adequately managed by the *Fatigue Monitoring* program (B3.1) for the subsequent period of extended operation.

4.3.2.3 Reactor Coolant Pump

TLAA Description:

The reactor coolant pumps (RCP) are Westinghouse design Model 93A. The RCPs were not designed to ASME Code, Section III. However, fatigue evaluations of the Reactor Coolant Pumps were performed to various editions of the ASME Code, Section III. Fatigue analyses that consider transient cycles that occur over the life of the plant constitute TLAAs as described in WCAP-18503-P.

TLAA Evaluation:

The evaluation of the Unit 1 and Unit 2 reactor coolant pumps were included in the MUR power uprate project. NRC Safety Evaluation Report for this project indicates no new transients were added to the licensing basis.

As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) are postulated to bound 80 years of plant operations. The CUF values will remain less than unity for the fatigue analyses of record during the subsequent period of extended operation. Therefore, the fatigue analysis for the reactor coolant pump components remains valid for the subsequent period of extended operation. In order to ensure the design cycles remain bounding in the reactor coolant pump fatigue analysis, the *Fatigue Monitoring* program (B3.1) will track cycles for significant fatigue transients listed in Table 4.3.1-1 and ensure corrective action is taken prior to potentially exceeding fatigue design limits.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of fatigue on the intended function(s) of the reactor coolant pump components will be adequately managed by the *Fatigue Monitoring* program (B3.1) for the subsequent period of extended operation.

4.3.2.4 Reactor Vessel

TLAA Description:

The RV fatigue evaluations were performed to the requirements of ASME Code, Section III. Fatigue analyses that consider transient cycles that occur over the life of the plant constitute TLAAs as described in WCAP-18503-P.

TLAA Evaluation:

There were five projects that could have potentially affected the transients in the reactor vessel design since the initial license renewal. These projects include the Unit 2 Upflow Conversion, the Core Exit Thermocouple Nozzle Assembly (CETNA), the 17 x 17 Robust Fuel Assembly Fuel Transition Reload, the replacement RV closure heads, and the MUR power uprate.

For Unit 1 and 2, the original closure head have been replaced with a closure head fabricated by Framatome ANP for a French utility power plant, but was purchased by Dominion. The replacement closure heads were fabricated and manufactured in accordance with the French Construction Code (RCC-M), “Design and Construction Rules for the Mechanical Components of PWR Nuclear Islands” (Reference 4.8-36). The sizing calculations and the stress and fatigue analysis were performed to ASME Code, Section III, 1995 Edition with Addenda through 1996. The Design Reports certified that the closure heads meet the design requirements and stress limits for ASME Code, Section III, 1968 Edition with Addenda through 1968. Additional details are provided in UFSAR, Section 5.4.1.1. The AOR fatigue CUF results are less than 1.0.

As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) are postulated to bound 80 years of plant operations. The CUF values will remain less than unity for the fatigue analyses of record during the subsequent period of extended operation.Therefore, the fatigue analyses for the RV components remain valid for the sub sequent period of extended operation. In order to ensure the design cycles remain bounding in the RV component fatigue analyses, the *Fatigue Monitoring* program (B3.1) will track cycles for significant fatigue transients listed in Table 4.3.1-1 and ensure corrective action is taken prior to potentially exceeding fatigue design limits as described in WCAP-18503-P.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of fatigue on the intended function(s) of the RV components will be adequately managed by the *Fatigue Monitoring* program (B3.1) for the subsequent period of extended operation.

4.3.2.5 Steam Generators (including Unit 1 Inlet Nozzle SWOLs)

TLAA Description:

Unit 1 and Unit 2 steam generators are a combination of replacement steam generator components and original steam generator components. The transition cone just below the upper shell was severed and the lower portion was removed and replaced with a replacement steam generator in 1993 for Unit 1 and 1995 for Unit 2. The upper shell with its steam separation equipment was retained and welded to the lower replacement portion. The result is a unit consisting of a lower shell and tube bundle of a Westinghouse Model F54 steam generator, and the modified feedwater and steam separation equipment of the original steam generator. All steam generator components, both original and replacement, were evaluated to the same loading conditions. The shell side of the steam generator conforms to the requirements for Class A vessels and is so stamped as permitted under the rules of ASME Code, Section III. The fatigue evaluations of the steam generator were performed to the requirements of ASME Code, Section III. Fatigue analyses that consider transient cycles that occur over the life of the plant constitute TLAAs. AOR fatigue CUF results are less than 1.0 as described in WCAP-18503-P.

SWOLs were installed on the Unit 1 steam generator inlet nozzles in 2012 for mitigation of PWSCC. Fatigue evaluations were performed for the Unit 1 steam generator inlet nozzle SWOLs using the original design basis transients and qualified for the original design of 40 years of cyclic operation. Fatigue evaluations for the FSWOLs are considered TLAAs.

TLAA Evaluation:

As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles), as amended by the MUR power uprate project, are postulated to bound 80 years of plant operations. The CUF values will remain less than unity for the fatigue analyses of record during the subsequent period of extended operation. Therefore, the fatigue analyses for the steam generator components remain valid for the subsequent period of extended operation. In order to ensure the design cycles remain bounding in the steam generator component fatigue analyses, the *Fatigue Monitoring* program (B3.1) will track cycles for significant fatigue transients listed in Table 4.3.1-1 and ensure corrective action is taken prior to potentially exceeding fatigue design limits as described in WCAP-18503-P.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of fatigue on the intended function(s) of the steam generator component will be adequately managed by the *Fatigue Monitoring* program (B3.1) for the subsequent period of extended operation.

4.3.2.6 Pressurizer Surge Line

TLAA Description:

NRC Bulletin 88-11, issued in December 1988, requested utilities to establish and implement a program to confirm the integrity of the pressurizer surge line. The program required both visual inspection of the surge line and demonstration that the design requirements of the surge line are satisfied, including the consideration of stratification effects. The demonstration was an ASME Code, Section III, NB-3200 fatigue analysis to account for thermal stratification. The analysis uses time-limited assumptions such as thermal and pressure transients and operating cycles for the licensed life of the plant. Therefore, the analyses required by NRC Bulletin 88-11 met the criteria of 10 CFR 54.3(a) and have been identified as TLAAs requiring evaluation for 80 years.

TLAA Evaluation:

The original analyses performed to demonstrate compliance with design requirements considered ASME Code requirements and utilized the design set of NSSS transients. Pressurizer surge line stratification sub-transients were developed based on plant operating procedures, surge line monitoring data from similar units and historical plant records. The CUF values will remain less than unity for the fatigue analyses of record during the subsequent period of extended operation.The surge line is identified as a fatigue sentinel location and is described in Section 4.3.4, Environmentally-Assisted Fatigue. When considering EAF, Dominion Energy elected to utilize ASME Code, Section XI, Appendix L instead of conducting fatigue analysis under ASME Code, Section III, NB-3200. In response to NRC Bulletin 88-11, the ASME Code, Section III, stress limits and cumulative usage factor requirements were shown to be acceptable for the current licensed life.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of fatigue on the intended function(s) of the pressurizer surge line will be adequately managed by the *Fatigue Monitoring* program (B3.1) for the subsequent period of extended operation. The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1) will manage the pressurizer surge line thermal stratification through inspection every ten years based upon the ASME Code, Section XI, Appendix L methodology approved by the NRC.

4.3.2.7 Class 1, USAS (ANSI) B31.7 Piping

TLAA Description:

The Class 1 pressure boundary piping, which includes both the RCS and auxiliary line piping, is designed to the USA Standard (USAS) Code B31.7-1969, Nuclear Power Piping with 1970 and 1971 Addenda. The reactor coolant loop piping, including the branch nozzles attached to the main loop piping, were evaluated by Westinghouse while the auxiliary line piping analysis qualification was performed by Stone & Webster during construction of Unit 1 and Unit 2. Piping systems designed in accordance with USAS (ANSI) B31.7 require analysis of cumulative fatigue usage (CUF).

During initial license renewal, and as an NRC commitment to a request for additional information (RAI), Unit 1 and Unit 2 performed detailed fatigue calculations including reactor water environmental effects on the 3" charging line branch nozzle and 12" accumulator line branch nozzle. Evaluations for these two locations are not updated as part of the SLR. Therefore, the analysis of CUF are TLAAs requiring evaluation for the subsequent period of extended operation.

TLAA Evaluation:

The design for the reactor coolant pressure boundary piping, branch nozzles attached to the main reactor coolant loop (RCL) piping, and the auxiliary line piping connected to the reactor coolant branch nozzles include detailed stress and fatigue evaluations in accordance with the methods of the ASME Code, Section III. The AOR fatigue CUF results are less than 1.0.

Section 4.4 of WCAP-18503-P provides fatigue analysis details and clarifications with respect to transients for the Class 1, USAS (ANSI) B31.7 RCL and auxiliary piping. Class 1 auxiliary piping locations are summarized as follows:

- Bypass Relief Line
- Charging Line
- Safety Injection Line
- Letdown Line
- Loop Drain Line
- Loop Fill Line
- Pressurizer Safety and Relief Lines
- Pressurizer Spray Lines
- Pressurizer Surge Line
- RCP Seal Water Inlet Line
- RHR and Accumulator Line

The fatigue design transients of the Class 1, USAS (ANSI) B31.7 piping is the same as the fatigue transients for the Class 1, ASME Code, Section III vessels. As shown in Table 4.3.1-1, and Section 3 of WCAP-18503-P, the 40-year design cycles (CLB cycles) are postulated to bound 80 years of plant operations. Therefore, the fatigue analyses for the Class 1, USAS (ANSI) B31.7 piping consisting of the reactor coolant piping, branch nozzles attached to the main RCL piping, and the auxiliary line piping connected to the reactor coolant branch nozzles remain valid for the subsequent period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The transient cycles considered in the USAS (ANSI) B31.7 for the reactor coolant piping, branch nozzles attached to the main RCL piping, and the auxiliary line piping connected to the reactor coolant branch nozzles bound the corresponding 80-year projected transient cycles in WCAP-18503-NP, Tables 3-3 through 3-6 for all transients. Therefore, the CUF values will remain less than unity for the fatigue analyses of record during the subsequent period of extended operation and thus this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

4.3.2.8 Loop Stop Isolation Valves (LSIV)

TLAA Description:

Subsequent to the initial license renewal, fatigue evaluations have been performed for several of the components for the loop stop isolation valves (LSIV). The stop valves were conservatively evaluated for the effect of an increased number of steam generator tube rupture transient cycles for initial license renewal. The steam generator tube rupture is a design basis accident but one cycle of this event occurred at NAPS early in the plant life. For the updated fatigue evaluation the number of cycles for this event was increased from 1 to 5 and the effect of this increase was conservatively included into the fatigue evaluations. The results of this evaluation were two fold; 1) confirmation that the increased number of cycles do not impact the fatigue waivers for the stop valve and 2) a set of slightly increased CUF values for the applicable stop valve components. Stresses were not rederived as part of this effort so the update was focused on the postulated increase to the number of transient cycles. The LSIVs are designed in accordance with ASME Code, Section III, Class 1 and require analysis of cumulative fatigue usage (CUF). Therefore, the analysis of CUF are TLAAs requiring evaluation for the subsequent period of extended operation.

TLAA Evaluation:

Westinghouse performed fatigue evaluations for several LSIV equipment locations as part of the MUR power uprate project. These locations included the valve main body, valve bonnet, canopy seal ring - weld, main flange bolts, backseat and glands - backseat rind weld, backseat and glands - secondary gland studs, and stem. The only locations with CUF values greater than 0.00 are the canopy seal ring - weld, main flange bolting, backseat and glands - backseat ring weld, and backseat and glands - secondary glands stud. The canopy seal ring - weld has a CUF value of 0.026 which is less than unity. The main flange bolting (nonwetted) resulted in CUF <1.0 for both Unit 1 and Unit 2. The backseat and glands - backseat ring weld and backseat and glands - secondary glands stud have CUF values of 0.05 which is less than unity.

As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) are postulated to bound 80 years of plant operations. The CUF values will remain less than unity for the fatigue analyses of record during the subsequent period of extended operation. Therefore, the fatigue analysis for the loop stop isolation valve components remains valid for the subsequent period of extended operation. In order to ensure the design cycles remain bounding in the LSIV fatigue analysis, the *Fatigue Monitoring* program (B3.1) will track cycles for significant fatigue transients listed in Table 4.3.1-1 and ensure corrective action is taken prior to potentially exceeding fatigue design limits.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of fatigue on the intended function(s) of the LSIVs will be adequately managed by the *Fatigue Monitoring* program (B3.1) for the subsequent period of extended operation.

4.3.2.9 ASME Code, Section III, Class 1 Component Fatigue Waivers

TLAA Description:

Fatigue analyses are required to be performed for ASME Code, Section III, Division 1, Class 1 components in accordance with the ASME Code, Section III, paragraph NB-3222.4. Each analysis is required to demonstrate that the CUF for the component will not exceed the design limit of 1.0 for the fatigue cumulative usage factor. A detailed fatigue evaluation is not required if components conform to the waiver of fatigue requirements of ASME Code, Section III. Fatigue waivers that consider transient cycles that occur over the life of the plant constitute TLAAs. ASME Code, Class 1 component fatigue waivers are discussed in this section.

The following equipment have sub-components that conform to the waiver of fatigue requirements in ASME Code, Section III.

Control Rod Drive Mechanisms

- Upper Joint - Cap
- Upper Joint - Rod Travel Housing

Loop Stop Isolation valves

- Valve Main Body-Shell/Bonnet Intersection

Reactor Coolant Pumps

- Casing
- Main Flange
- Seal Housing
- Ring Clamp
- Ring Clamp Bolts
- Weir Plate (Discharge Nozzle)
- Casing Feet

TLAA Evaluation:

To address the metal fatigue TLAAs identified as part of SLR, the CLB fatigue waivers for the ASME Code, Section III, Class 1 components were determined by reviewing the TLAA identification work performed for initial license renewal and updating it to incorporate any fatigue-related work that has been performed to-date. This review yielded the list of components with fatigue waivers summarized above.

The transients associated with each evaluation were consolidated into an overall transient set applicable to the fatigue waivers identified above. In order to document that the CLB fatigue waivers remain valid and bounding through the subsequent period of operation, transient cycle projections for 80 years of operation were compared against the CLB cycles for each transient.

As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) are postulated to bound 80 years of plant operations. Therefore, the fatigue waivers for Class 1 components remain valid for the subsequent period of extended operation as described in WCAP-18503-NP. In order to ensure the design cycles remain bounding in the ASME Code, Section III, Class 1 component fatigue waivers, the *Fatigue Monitoring* program (B3.1) will track cycles for significant transients and ensure corrective action is taken prior to potentially exceeding fatigue design limits.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The ASME Code, Section III, Class 1 component fatigue waivers will be managed by the *Fatigue Monitoring* program (B3.1) through the subsequent period of extended operation. The *Fatigue Monitoring* program (B3.1) will monitor the transient cycles and severities which are the inputs to the fatigue waiver analyses and require action prior to exceeding design limits that would invalidate their conclusions.

4.3.3 USAS (ANSI) B31.1 ALLOWABLE STRESS ANALYSES

TLAA Description:

Nuclear piping is constructed in accordance with the USAS (ANSI) B31.7, “Nuclear Power Piping” Code, 1969 Edition with 1970 and 1971 Addenda. USAS (ANSI) B31.7-69, Class I piping is designed to consider the cumulative effect of stress cycles by use of a cumulative usage factor (CUF). Fatigue for Class I piping is addressed as a TLAA in Section 4.3.2.7.

As identified in USAS (ANSI) B31.7-69 paragraphs 2-702 and 3-702, Class II and Class III piping meets the design criteria of USAS (ANSI) B31.1.0-1967, Division 102. Non-nuclear (Balance of Plant) piping is constructed to “The Power Piping Code” USAS (ANSI) B31.1, 1967 Edition with 1969 Addenda.

For piping systems designed in accordance with USAS (ANSI) B31.1, explicit analyses of cumulative fatigue usage are not required. Instead, cyclic loading is considered in a simplified manner in the design process. Allowable thermal stresses are reduced using a stress range reduction factor based on the number of anticipated thermal cycles expected during the component operating lifetime. Stress range reduction factors are specified in USAS (ANSI) B31.1, Table 102.3.2(c). No reduction of allowable stresses is required for piping that is subjected to less than 7,000 equivalent full temperature cycles during plant service. The stress range reduction factor for higher numbers of fatigue cycles is less than 1.0 and is gradually reduced until a range of 100,000 cycles is reached. For piping anticipated to experience 100,000 or more equivalent full temperature cycles, the allowable stress range would be reduced to half of the maximum nominal allowable stress. The evaluations for required stress reduction factors are implicit fatigue analyses because they are based on the number of fatigue cycles anticipated for the life of the component. Therefore, they are TLAAs requiring evaluation for the subsequent period of extended operation.

TLAA Evaluation:

USAS (ANSI) B31.1 systems are generally subject to continuous steady state operation and operating temperatures vary only during plant heatup and cooldown, during plant transients, or during periodic testing. Portions of piping systems designed in accordance with USAS (ANSI) B31.1 requirements that are attached to the reactor coolant system or other power cycle related systems are subject to a similar number or fewer cycles as the reactor coolant system. These include condensate, containment vacuum, extraction steam, feedwater, primary and secondary gas supply, main steam, reactor coolant, steam drains, and vacuum priming systems. Portions of some of these systems are normally isolated from the normal power cycle and would experience fewer cycles than those portions at the system boundary. The expected number of transients for these systems is much less than 7,000 cycles, therefore, the stress range reduction factors applied to the piping remain applicable and the implicit TLAAs remain valid for the subsequent period of extended operation.

Portions of the following systems, designed in accordance with USAS (ANSI) B31.1 requirements, are affected by thermal and pressure transients that are different than the reactor coolant and power cycles discussed above: alternate AC, auxiliary boilers, auxiliary steam, blowdown, chilled water, chemical and volume control, emergency diesel generator, high radiation sampling, heating and ventilation, residual heat, security, and sampling system. The basis for cycle projections have been reviewed for these systems to validate that the projected cycles for 80 years remain less than 7,000 cycles. Table 4.3.3-1 and Section 4.4.2 of WCAP-18503-P provide the basis for concluding that the number of cycles for each of these piping systems is projected to be less than 7,000. Therefore, the USAS (ANSI) B31.1 allowable stress analyses remain valid for the subsequent period of extended operation.

Initial license renewal validated that the USAS (ANSI) B31.1 piping would receive less than 7,000 cycles. For SLR, it is confirmed that the USAS (ANSI) B31.1 piping is projected to receive less than 7,000 cycles.

In addition, no component in the systems identified by Table 4.3.3-1 were designed in accordance with ASME Code, Section VIII, Division 2.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The USAS (ANSI) B31.1 allowable stress analyses remain valid for the subsequent period of extended operation.

Table 4.3.3-1 80 Year Transient Cycle Projections for USAS (ANSI) B31.1 Piping

Description	Conservative Basis for Cycle Projection	Projected Cycles for 80 years
Alternate AC (AAC) diesel engine exhaust piping	10 starts per year, since installation of the AAC diesels in 1992 to 2060 (10 cycles/year x 68 years = 680 cycles).	Less than 1000 cycles
Auxiliary Boilers (AB)	Cycles for the AB System piping are bounded by the number of AS System thermal cycles.	Less than 2000 cycles
Auxiliary Steam (AS)	20 cycles per year - 1600 cycles.	Less than 2000 cycles
Blowdown (BD)	10 cycles per year - 800 cycles.	Less than 1000 cycles
Chilled Water (CD)	Cycles for the CD system piping are bounded by the number of AS System thermal cycles.	Less than 2000 cycles
Chemical and Volume Control (CH)	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1.	Less than 7000 cycles
Condensate (CN)	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1.	Less than 7000 cycles
Containment Vacuum (CV)	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1.	Less than 7000 cycles
Emergency Diesel Generator (EG)	Twice per month to account for monthly (historic) surveillance testing (currently conducted quarterly) and post maintenance testing (2 cycles/month x 12 month/year x 80 years = 1920).	Less than 2000 cycles
Extraction Steam (ES)	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1.	Less than 7000 cycles
Feedwater (FW)	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1.	Less than 7000 cycles
Primary and Secondary Gas Supply (GN)	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1.	Less than 7000 cycles
High Radiation Sampling (HRS)	Simultaneous sampling by the HRS system and the PSS is prevented by interlocks. Projected 80-year thermal cycles is well below 1000	Less than 1000 cycles
Heating and Ventilation (HV)	Cycles based on seasonal heating. Conservatively assume 85 cycles per year (80 years x 85/year = 6800 cycles).	Less than 7000 cycles
Main Steam (MS)	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1	Less than 7000 cycles
Reactor Coolant (RC)	RCS transients from Table 4.3.1-1.	Less than 7000 cycles
Residual Heat (RH)	System piping heated during shutdowns and startups. 2 per heatup and cooldown each refueling cycle.	Less than 1000 cycles
Steam Drains (SD)	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1.	Less than 7000 cycles
Security (SEC)	Twice per month to account for monthly testing and post maintenance testing (2 cycles/month x 12 months/year x 80 years = 1920).	Less than 2000 cycles

Description	Conservative Basis for Cycle Projection	Projected Cycles for 80 years
Sampling System (SS)	Pressurizer Liquid Space Samples 10 cycles per year - 800 cycles	Less than 1000 cycles
	RHR Heat Exchanger Inlet/Outlet Samples 10 cycles per year - 800 cycles.	Less than 1000 cycles
	RCS Hot Leg and RCS Cold Leg Samples Unit 1: Through first 57 plant operating cycles (before 2015) there were 100 samples/plant operating cycle. After 2015, there are projected 1 sample per 42 remaining plant operating cycles. [(57 x 100) + (42 x 1)] = 5742 cycles Unit 2: Through first 52 plant operating cycles (before 2015) there were 100 samples/plant operating cycle. After 2015, there are projected 1 sample per 61 remaining plant operating cycles. [(52 x 100) + (61 x 1)] = 5261 cycles	Less than 6000 cycles
Vacuum Priming System (VP)	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1.	Less than 7000 cycles

4.3.4 ENVIRONMENTALLY-ASSISTED FATIGUE

TLAA Description:

As outlined in Section X.M1 of NUREG-2191 and Section 4.3 of NUREG-2192, the effects of the reactor water environment on the fatigue cumulative usage factor (CUF) must be examined for a set of sample critical components for the plant. This sample set includes the locations identified in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components" (Reference 4.8-37) 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, Table 5-98. 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 components and USAS (ANSI) B31.7 piping, including the NUREG/CR-6260 locations, to determine the lead indicator (also referred to as sentinel) locations for EAF.

TLAA Evaluation:

To support subsequent license renewal, calculations were prepared to document the evaluations of EAF for ASME Code, Section III pressure boundary components and USAS (ANSI) B31.7, Class I piping that contact the reactor coolant, and determine fatigue-sensitive locations for comparison and ranking. These evaluations are for subsequent license renewal purposes and do not amend the existing design reports. This TLAA evaluation is presented separately for ASME Code, Section III and USAS (ANSI) B31.7 components and piping. Discussion of the screening approaches used for the ASME Code, Section III Components and USAS (ANSI) B31.7 piping is provided below due to slight differences in the screening approaches used. As a result of the EAF screening evaluation, there were other locations found that could potentially be more limiting than the NUREG/CR-6260 locations as documented in WCAP-18503-P and SIA Report 1701098.403P, Revision 0, "Determination of Final Set of Environmentally-Assisted Fatigue (EAF) Sentinel Locations for North Anna Power Station (NAPS) Units 1 and 2," (Reference 4.8-38). A consolidated tabulation for ASME Code, Section III pressure boundary components and piping is presented for the sentinel locations in Table 4.3.4-2.

ASME Code, Section III Components

The nuclear steam system supplier (NSSS) vendor performed the EAF screening for the Class 1 equipment and main loop piping. The next subsection, entitled "USAS (ANSI) B31.7, Class I Piping," discusses the integration of the EAF screening results for the main loop piping with the Class 1 auxiliary piping locations to provide a comprehensive list of sentinel location for all of the applicable piping systems.

In the EAF screening process for ASME Code, Section III components, all applicable ASME Code, Section III components that are susceptible to EAF were reviewed and categorized into common systems, or transient sections. Screening F_{en} factors were developed so that each component's cumulative usage factor environmentally adjusted (CUF_{en}). Values can be calculated and compared. CUF_{en} is interchangeable with the term EAF Cumulative Usage Factor (U_{EN}). The methodology outlined in NUREG/CR-6909, “Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials, Final Report” (References 4.8-39) is used for stainless steels, carbon and low-alloys steels, and Ni-Cr-Fe alloys. The initial EAF screening results for sentinel locations is based upon the most bounding F_{en} values in NUREG/CR-6909 Revision 1, (Reference 4.8-40).

Conservative values are chosen for each of the F_{en} input parameters: sulfur content, service temperature, strain rate, and dissolved oxygen (DO). EPRI Technical Report TR3002000505, “Pressurized Water Reactor Primary Water Chemistry Guidelines” (Reference 4.8-41) is followed. Therefore, the F_{en} calculation considers a value of 0.005 ppm for the DO content when the system temperatures are elevated, which is the action level 1 value for PWR environmental conditions under normal operation. DO is sampled in the reactor coolant system 5 times per week and runs less than 0.005 ppm.

For the periods during heatup/cooldown operations when DO may be elevated, pressurizer temperature is ≤ 250°F (121°C). During these times, the system ΔT between the pressurizer and RCS is low (≤ 80°F), and pressurizer insurge/outsurge transient events with this magnitude of system ΔT are not significant contributors to fatigue. For pressurizer temperatures above 250°F, Hydrazine addition is used to control and reduce dissolved oxygen. For cooldown, H_2 concentration in the RCS is used to minimize dissolved oxygen in the RCS through the time of pressurizer steam bubble collapse. Furthermore, fluid temperatures during the elevated DO times are in the range where T* values are the lowest. In the formulas presented in NUREG/CR-6909, Revision 1 for Carbon and Low-Alloy steels, the relationship for T* is linear while O* is logarithmic, which implies the increase in O* may be offset by the decrease in T*. Therefore, the use of 0.005 ppm for DO content is acceptable for the F_{en} evaluations.

For the systems where the NUREG/CR-6260 locations have the highest screening CUF_{en} no additional locations were considered as sentinel locations. For those systems where the NUREG/CR-6260 locations do not have the highest screening CUF_{en} or a NUREG/CR-6260 location does not exist, the locations within that system that have the highest screening CUF_{en} in excess of unity are the EAF sentinel locations. The final set of sentinel locations are meant to supplement those identified in NUREG/CR-6260, resulting in a comprehensive list of plant-specific primary equipment sentinel locations for EAF consideration.

Any location that was not part of the ASME Code, Section III reactor coolant pressure boundary was removed from consideration. Other locations were also excluded during this step and included locations not in contact with primary coolant, locations excluded from fatigue usage factor calculation based on fatigue waivers, and locations with a CUF of 0.0.

Sentinel locations for ASME Code, Section III components were identified as follows:

- Components with a screening CUF_{en} of less than unity were removed.
- Stress basis analysis ranking, which is a consistent ranking approach to assess the level of technical rigor and qualification criteria for each component within the transient section, was assessed for each remaining component.
- The location with the maximum screening CUF_{en} in each transient section, for each applicable material type, was retained.
- Comparison of candidate-sentinel locations against any NUREG/CR-6260 locations within the system was completed. Components with a CUF_{en} less than the NUREG/CR-6260 location were removed from the final set of sentinel locations.

The results of the EAF calculations for the sentinel locations are summarized in Table 4.3.4-2. In addition to the CUF_{en} values, the original AOR CUF, the reduced CUF developed for SLR, and a brief summary of the conservatisms removed from the AOR for ASME Code, Section III components are also provided in Table 4.3.4-2.

USAS (ANSI) B31.7, Class I Piping

EPRI Report 1024995, "Environmentally Assisted Fatigue Screening: Process and Technical Basis for Identifying EAF Limiting Locations (Reference 4.8-42) was used as a guide for EAF screening of USAS (ANSI) B31.7 Class I piping. Structural Integrity Associates, Inc. (SIA) performed the EAF screening for the branch USAS (ANSI) B31.7 Class I piping. In the EAF screening process for USAS (ANSI) B31.7 Class I piping with explicit fatigue evaluations and calculated cumulative usage factor (CUF) values, all applicable Class I piping locations that are susceptible to EAF were reviewed and categorized into common systems and consolidated transient sections. The consolidated transient sections were defined by the NSSS vendor as described in the following table:

Table 4.3.4-1 Consolidated Safety Class 1 Piping Transient Sections

Consolidated Transient Section	Transient Sections
SI and Reactor Coolant Transients (Cold Leg)(1)	Cold Leg
	Loop Fill
	Crossover Leg
	RCP Seal Injection
	Loop Bypass(4)
	SI Line - Cold Leg
	Accumulator
RHR and Reactor Coolant Transients (Hot Leg)(2)	Hot Leg
	Loop Bypass(4)
	RHR Suction
	RHR Return (Accumulator and SI - Hot Leg)
Charging (Normal and Alternate)	Charging (Normal and Alternate)
Letdown (Normal Letdown, Excess Letdown, Loop Drain)	Letdown
	Excess Letdown and Drain
PZR Lower Head and Surge Line	PZR Surge Line
PZR Upper Head and Shell	PZR Spray and Auxiliary Spray Line
PZR Safety and Relief Lines(3)	PSARV - Safety Line
	PSARV - Relief Line

Notes:

1. The transient sections noted in this consolidated section are exposed to RCS T_{cold} transients. The Accumulator and SI Line - Cold Leg transient sections are also exposed to auxiliary transients.
2. The transient sections noted in this consolidated section are exposed to RCS T_{hot} transients. The Accumulator transient section is exposed to RCS T_{cold} transients, but is part of the RHR Return path. The RHR Suction and Return transient sections are also exposed to auxiliary transients.
3. The PSARV - Safety Line and PSARV - Relief Line transient sections are exposed to the same thermal transients, except the PSARV - Relief Line transient section is subjected to more cycles of this thermal event. In addition, there are no recorded occurrences of the safety valves lifting, thus the actual mechanical loadings for the components located in the PSARV - Safety Line transients section are lower than the design loadings. In addition, based on a review of the AORs, the components located on the relief line are more limiting than those on the safety line, thus further supporting the consolidation of the PSARV - Safety Line and PSARV - Relief Line transient sections.
4. The loop bypass transient section is comprised of multiple lines that are subject to either cold leg or hot leg transients.

Screening F_{en} multipliers were developed for each component so that CUF_{en} values can be calculated and compared. The methodology outlined in NUREG/CR-6909, "Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials, Final Report" (References 4.8-39 and 4.8-40) is used for stainless steels, carbon and low-alloys steels, and Ni-Cr-Fe alloys. NUREG/CR-6909, Revision 0 (Reference 4.8-39) is limiting for stainless steel and nickel based (Ni-Cr-Fe) alloy materials while NUREG/CR-6909, Revision 1 is limiting for carbon and low-alloy steels. Thus, similar to how screening was performed for the ASME Code, Section III Components, the initial EAF screening results for the Class 1 piping sentinel locations is based upon the most bounding values in NUREG/CR-6909 Revision 0 and Revision 1, for conservatism.

Conservative values are chosen for each of the F_{en} multiplier input parameters: sulfur content, service temperature, strain rate, and DO. EPRI Technical Report TR3002000505 is followed. Therefore, the F_{en} calculation considers a value of 0.005 ppm for the DO content when the system temperatures are elevated, which is the action level 1 value for PWR environmental conditions under normal operation. DO is sampled in the reactor coolant system 5 times per week and runs less than 0.005 ppm.

The screening process for the USAS (ANSI) B31.7 Class I piping were identified as follows:

- Piping locations with a screening CUF_{en} < 0.80 using the most conservative F_{en} multipliers from NUREG/CR-6909 were removed.
- Within each material type in a thermal zone, the location with the highest estimated or maximum CUF_{en} was selected during initial screening; the location with the second highest CUF_{en} is also selected if the second highest CUF_{en} value is greater than 50% of the highest. If the third-highest CUF_{en} value is greater than 25% of the highest CUF_{en} value within a thermal zone, then the top three locations in that thermal zone was selected. This methodology yielded a significant number of initial potential EAF sentinel locations for USAS (ANSI) B31.7 Class I piping.
- For the initial set of potential EAF sentinel locations, piping thermal zones were consolidated into transient sections by Westinghouse as described in WCAP-18503-P.
- Piping locations with the maximum screening CUF_{en} in each transient section, for each applicable material type, were retained for further evaluation.
- Comparison of candidate EAF sentinel locations to any NUREG/CR-6260 locations within the system and the consolidated transient sections was also performed. Piping locations with a CUF_{en} less than the NUREG/CR-6260 locations were removed from the final set of sentinel locations.
- For two transient sections (Letdown and Pressurizer Safety and Relief Lines), refined methodologies were used based on the 1980 Edition of ASME Code, Section III, Subsection NB-3600, to demonstrate these EAF sensitive locations are acceptable using transient cycle limits.

The results of the EAF calculations for the sentinel locations are summarized in Table 4.3.4-2. The U_{en} values for transient sessions 4 and 7 are less than unity therefore fatigue management is not required for these transient sections. In addition to the CUF_{en} values, the original AOR CUF, the reduced CUF developed for SLR, and a brief summary of the conservatisms removed from the AOR for ASME Code, Section III components and USAS (ANSI) B31.7 Class I piping are also provided in Table 4.3.4-2. The CRDM head adapters J-groove welds is the bounding EAF location for nickel-based material including the pressurizer surge nozzle.

As described in the initial license renewal Safety Evaluation Report NUREG-1766, Dominion stated that in response to NRC IE Bulletin 88-11, the pressurizer surge lines were analyzed for the insurge/outsurge event, which imposed thermal loads not considered in the original analyses. The NRC staff reviewed the issue of environmentally-assisted fatigue as part of the initial license renewal and Dominion conducted a separate analysis to determine whether additional actions were needed during the initial period of extended operation. Part of this new analysis was to determine the most fatigue-sensitive subcomponents. Among these was the pressurizer surge line, including the pressurizer surge nozzles and hot leg nozzles that attach the surge line to the main reactor coolant loop piping. The NRC considers the surge line a bounding example to represent the effects of the reactor water environment on the fatigue life of pressurizer components during the subsequent period of extended operation. In lieu of additional analyses to refine the CUF for the pressurizer surge line, Dominion elected at the time to implement an aging management program (AMP) to address environmental fatigue of the surge line for the period of extended operation. Specifically, the surge line weld at the hot leg pipe connection is examined in an augmented inspection program to provide reasonable assurance that the potential reactor water environmental effects will be managed such that components within the scope of license renewal will continue to perform their current licensing basis (CLB) function during the period of extended operation. Subsequent to approval of initial license renewal, Dominion performed a flaw tolerance evaluation for the pressurizer surge line in accordance with ASME Code, Section XI, Appendix L to validate the inspection frequency to be once every 10 years.

Sentinel Locations

Sentinel locations are those locations chosen for more detailed analysis, monitoring, inspection, or replacement. These locations are chosen to have bounding CUF_{en} values compared with other locations within the same transient section.

The results of the EAF calculations for the ASME Code, Section III components and USAS (ANSI) B31.7 Class 1 piping of the reactor coolant pressure boundary piping (greater than one-inch diameter) out to the second isolation valve are summarized in Table 4.3.4-2.

Fatigue Management

For the ASME Code, Section III components with CUF_{en} greater than 1.0, ASME Code, Section III, NB-3200 calculations were prepared to remove conservatisms used in the AOR, thereby reducing the CUF_{en} to less than 1.0. The effects of fatigue on the intended functions of these ASME Code, Section III components will be managed by the *Fatigue Monitoring* program (B3.1) through the use of cycle counting. This approach was applied to the following components:

- Pressurizer surge nozzle FSWOL
- Pressurizer spray nozzle FSWOL (stainless steel pipe to safe-end weld)

For the replacement reactor vessel closure head (RRVCH) flange, the CUF_{en} was reduced to less than 1.0 by using fatigue curve from NUREG/CR-6909.

For two pressurizer FSWOL nozzle locations with U_{en} values greater than unity, Surge Nozzle (Ni-Cr-Fe), and Spray Nozzle (stainless steel pipe to safe weld) these locations will be managed through the *Fatigue Monitoring* program (B3.1) during the subsequent period of extended operation. While not required for EAF since these FSWOLs are managed by the *Fatigue Monitoring* program (B3.1), they are inspected in accordance with ASME Code Case N-770-2.

For sentinel piping locations, the effects of fatigue will be managed by application of the Inservice Inspection program (*ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1)) during the subsequent period of operation based on results of flaw tolerance evaluations conducted in accordance with the guidance of ASME Code, Section XI, Nonmandatory, Appendix L. NUREG-2192 permits inspections as a management method for fatigue as long as a flaw tolerance evaluation is performed to determine the acceptable time between inspections. The ASME Code, Section XI, Appendix L crack growth evaluation is used in conjunction with calculated allowable flaw sizes to determine the required inspection interval for a postulated flaw in the piping at the bounding location. For a postulated initial flaw, crack growth is simulated until the flaw has reached the allowable flaw depth or the end of the subsequent period of extended operation, whichever comes first.

The purpose of the flaw tolerance evaluation is to establish an appropriate inspection frequency that is consistent with the typical 10-year inservice inspection program for the auxiliary piping systems. The input used from each of the auxiliary piping systems (geometry, transient cycles and definitions, material properties, piping loads, etc.) bound both Units 1 and 2. The ASME Code, Section XI, Appendix L flaw tolerance evaluation consists of postulating a hypothetical inside surface axial and circumferential flaw. There are four sentinel locations analyzed using ASME Code, Section XI, Appendix L presented in Table 4.3.4-2. Two approaches were used to analyze the sentinel locations. The first approach is for the pressurizer surge line. The second approach is for the remaining three branch line piping locations.

The pressurizer surge line ASME Code, Section XI, Appendix L evaluation used transients to simulate growth of the postulated flaws prorated over ten years of operation. Transients used in the pressurizer surge line ASME Code, Section XI, Appendix L evaluation are tracked by the *Fatigue Monitoring* program (B3.1). Dominion transmitted Letter 20-049 to request NRC review and approval of a revision to the inspection plan for the pressurizer surge line based upon completion of a flaw tolerance evaluation in accordance with ASME Code, Section XI, Appendix L.

For the branch line piping, the transients used to simulate growth of the postulated flaws in the ASME Code, Section XI, Appendix L evaluations used cycles intended to be conservative for ten years of operation. The combined selection of transients and inspection frequency is very conservative, thereby ensuring the inspection frequencies remain adequate. The transients used to simulate growth of the postulated flaws in the ASME Code, Section XI, Appendix L evaluation fall into two categories. The first group of transients is associated with the reactor coolant loop piping. The second group of transients includes both transients associated with the reactor coolant loop piping and branch line piping. The transients for the reactor coolant piping are a subset of transients applicable to the ASME Code, Section III components. The *Fatigue Monitoring* program (B3.1) tracks significant transient cycles for:

(1) the ASME Code, Section III components,

(2) the insurge and outsurge cycles pertaining to the pressurizer surge line, and

(3) the branch nozzles analyzed with ASME Code, Section XI, Appendix L evaluations.

Following re-inspection the cycle counts used in the ASME Code, Section XI, Appendix L evaluation are set to zero when no relevant indication (NRI) is concluded for each new inspection interval.

The maximum allowable end-of-evaluation period flaw size was determined based on the acceptance criteria and evaluation procedures in ASME Code, Section XI, Appendix C, 2013 Edition which is the current code of record. In addition, it was confirmed that use of a fixed aspect ratio of six (6) produces the same time between inspections as the equivalent single crack aspect ratio provisions of ASME Code, Section XI, Appendix L, 2013 Edition. Based on previous inspection records, there are no detected indications at these auxiliary piping systems; therefore, the methodology of ASME Code, Section XI, Appendix L can be used. As per ASME Code, Section XI, Appendix L, a postulated initial flaw size larger than the ASME Code, Section XI acceptance standards in Table IWB-3514-2 (with aspect ratio of 6) was used in the fatigue crack growth (FCG) analysis. The piping systems evaluated here are constructed from stainless steel material, where the only significant crack growth mechanism of consideration is fatigue crack growth.

Based on the fatigue crack growth evaluation, the allowable operating period was determined as the length of time it takes for the postulated initial flaw size to grow to the maximum allowable end-of-evaluation period flaw size. The fatigue crack growth analysis was completed using the crack growth rates from ASME Code, 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, ASME International” (Reference 4.8-44). The results of the ASME Code, Section XI, Appendix L evaluations are provided in Table 4.3.4-3. See WCAP-18542-P, “North Anna Units 1 and 2, ASME Section XI Appendix L Flaw Tolerance Evaluation for Safety Injection, Charging and Accumulator Nozzles” (Reference 4.8-45) and SIA Report Number 1700553.402, “Flaw Tolerance Evaluation of the North Anna Unit 1 and 2 Hot Leg Surge Line Nozzles Using ASME Code Section XI, Appendix L” (Reference 4.8-46).

The U_{en} value for the 3-inch charging branch nozzle is less than unity, therefore management of EAF is not required for these locations. While management of EAF is not required, an ASME Code, Section XI, Appendix L, flaw tolerance evaluation confirmed that the time between inspections for the 3" charging branch nozzle is greater than 80 years. Inservice inspections of the ASME Code, Section XI, Appendix L piping (with the exception of the 3-inch charging branch nozzle) will be performed every ten years. Each weld in the inspection population (other than the 3-inch charging branch nozzle) will be ultrasonically inspected once prior to establishing the 7th and 8th Inspection Interval schedule for Units 1 and 2 ASME Code, Section XI, Appendix L locations. Going forward after the first ultrasonic inspection, one weld in each of the remaining two Appendix L groups will be ultrasonically inspected every 10 years: Surge Line, and Cold Leg Safety Injection. The ASME Code, Section XI, Appendix L inspections will be conducted by the Inservice Inspection (*ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1)) program. The ASME Code, Section XI, Appendix L inspections are identified in Table 4.3.4-4 for Unit 1 and in Table 4.3.4-5 for Unit 2. Operating transients used in the flaw tolerance evaluations performed under ASME Code, Section XI, Appendix L, are a subset of the transients listed in UFSAR Table 5.2.4 and UFSAR Section 18.4.2.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of fatigue on the intended function(s) of the ASME Code, Section III components and USAS (ANSI) B31.7 Class 1 piping (with Appendix L evaluations) will be adequately managed by the *Fatigue Monitoring* program (B3.1) for the subsequent period of extended operation. The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1) will manage piping locations with Appendix L evaluations. The *Steam Generators* program (B2.1.10) will manage fatigue of the steam generator tubing.

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Table 4.3.4-2 Sentinel Locations

Transient Sections	Location	Mat'l	AOR CUF	SLR CUF	F_{en}(1)	U_{en}(2)	Analysis Method	Fatigue Management Method
Section 1 **Reactor Coolant Transients** (Cold Leg)	RV Shell Transition(3),(4)	LAS	0.092	0.092	6.276	0.58	NUREG/CR-6260 Location ASME Code, Section III, Subsection NB-3200 (U_{en} < 1.0)	None Required (14)
	RV Inlet Nozzles and Support Pads (3),(4)	LAS	0.035	0.035	6.276	0.22	NUREG/CR-6260 Location ASME Code, Section III, Subsection NB-3200 (U_{en} < 1.0)	None Required (14)
	6" Branch Nozzle SI - Cold Leg (3)	SS	0.746	0.746	7.892	5.89	NUREG/CR-6260 Location (ASME Code, Section XI, Appendix L)	*ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1)
Section 2a(15) **RHR** (RHR plus High Head Injection Path)	12" Branch Nozzle Accumulator Cold Leg(3),(8),(16)	SS	0.6846	0.130	5.69	0.74	NUREG/CR-6260 Location ASME Code, Section III, Subsection NB-3200 (U_{en} < 1.0)	None Required
Section 2b **Reactor Coolant Transients** (Hot Leg)	RV Outlet Nozzles(3),(4)	LAS	0.089	0.089	6.276	0.56	NUREG/CR-6260 Location ASME Code, Section III, Subsection NB-3200 (U_{en} < 1.0)	None Required (14)

Table 4.3.4-2 Sentinel Locations

Transient Sections	Location	Mat'l	AOR CUF	SLR CUF	F_{en}(1)	U_{en}(2)	Analysis Method	Fatigue Management Method
<u>Section 2c</u> **Reactor Coolant Transients** (Steam Generator)	Steam Generator Tubes(4),(6)	Ni-Cr-Fe Alloy	0.421	0.421	37.46(10)	15.77	ASME Code Section III, Subsection NB-3200	*Steam Generators* program (B2.1.10)
<u>Section 3</u> **Charging** (Normal and Alternate)	3" Branch Nozzle Cold Leg(3)	SS	0.865	0.089(11)	3.0(11)	0.267	NUREG/CR-6260 Location ASME Code, Section III, Subsection NB-3200 (U_{en} < 1.0)	None Required
<u>Section 5</u> **Pressurizer Lower Head(7) and Surge Line**	14" branch PZR surge line hot leg	SS	0.966	0.966	8.856(12)	8.56	NUREG/CR-6260 Location (ASME Code, Section XI, Appendix L)	*ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1)
<u>Section 6</u> **Pressurizer Upper Head & Shell(7)**	PZR Spray Nozzle FSWOL, SS pipe to safe end weld(5),(13)	SS	0.750	0.750	8.856	6.64(9)	ASME Code, Section III, Subsection NB-3200	*Fatigue Monitoring* program (B3.1)-Cycle Counting SS safe-end inspected when surge nozzle FSWOL N-770-2 inspection performed.

Notes:

1. The F_{en} documented in this table is a factor that accounts for the environmental effects on metal exposed to primary side water chemistry.
2. For major component EAF screening, the methodology in NUREG/CR-6909, Revision 1 is used for all material types. For piping EAF screening, the methodology in NUREG/CR-6909, Revision 0 is used for stainless steel and Ni-Cr-Fe alloy materials while the methodology in NUREG/CR-6909, Revision 1 is used for carbon and low-alloy steels.
3. The NUREG/CR-6260 locations are retained as sentinel.
4. The U_{en} values for these major components are documented in WCAP-18503-NP.
5. The CUF value for the Pressurizer spray nozzle FSWOL safe end was calculated in Framatome document 51-9282308-000-P, April 2018.
6. This sentinel location is addressed through the *Steam Generators* program (B2.1.10). The steam generator tubes are examined by eddy-current testing.
7. The pressurizer is separated into two transient sections to represent the differences in thermal transients for regions affected by insurge/outsurge events (pressurizer lower head) and those not affected by insurge/outsurge events (pressurizer upper head/shell).
8. Though the Accumulator nozzle is located on the cold leg, the nozzle is also part of the RHR system.
9. The Pressurizer spray nozzle stainless steel safe end weld with a CUF = 0.750 and surge nozzle with a CUF=0.174 were removed from service by the Alloy 52M FSWOL in 2007. The FSWOL is inspected in accordance with Code Case N-770-2.
10. The F_{en} values for these locations applied an Fadj=10.0 multiplier as documented in WCAP-18503-P.
11. The F_{en} value for the 3" Charging Nozzle was calculated in NRC-approved “License Renewal - Response to RAI 4.3-6 (reference UFSAR Section 18.3.2.4, Table 18-1 Item 25).” SLR CUF = 0.089 from CN-PAFM-03-30 for initial license renewal.
12. The F_{en} value for the 14" Hot leg surge line nozzle is from 1701098.403.
13. All Pressurizer nozzle FSWOLs analyzed with design pressurizer transients.
14. CUF_{en} less than unity. No fatigue management required per GALL-SLR. Transients for this location are monitored in the Fatigue Monitoring program.
15. Zone 2a includes the high head injection paths for the following piping: Hot Leg, Loop Bypass, RHR Suction, RHR Return, Accumulator & Safety Injection.
16. The F_{en} value for the 12 inch accumulator nozzle was calculated in NRC-approved “License Renewal - Response to RAI 4.3-6 (reference UFSAR Section 18.3.2.4, Table 18-1, Item 25). SLR CUF = 0.130 from CN-PAFM-03-30 for initial renewal.

Table 4.3.4-3 ASME Code, Section XI, Appendix L Results

Auxiliary Line	Flaw Configuration	Aspect Ratio (a)	Acceptable Standards Flaw Size Table IWB-3510-1(b)	Final Flaw Size (a/t) (c)	Maximum Allowable End-of-Evaluation Flaw Size (a/t) (d)	Allowable Operating Period (Years)(e)
6" RCL Branch Safety Injection (SI) Nozzle (Cold Leg)	Axial	7	0.13	0.147	0.57	> 80
	Circumferential	7	0.13	0.142	0.34	> 80
3" RCL Branch Charging Nozzle (Cold Leg)(f) (For Information Only)	Axial	9	0.12	0.124	0.60	> 80
	Circumferential	9	0.12	0.130	0.45	> 80
12" RCL Branch Accumulator Nozzle (Cold Leg) - RHR	Axial	7	0.143	0.150	0.42	> 80
	Circumferential	7	0.143	0152	0.60	> 80
14" RCL Branch Pressurizer Surge Nozzle (Hot Leg)(g)	Axial	6	n/a	0.3565	0.3581	80
	Circumferential	6	n/a	0.3938	0.5344	60

Notes:

(a) Aspect Ratio (AR), defined as flaw length over flaw depth, is assumed to stay constant as the crack grows through the wall thickness.

(b) Initial postulated flaw size which is based on ASME Code, Section XI, Table IWB-3514-1 and Table IWB-3514-2 for an aspect ratio of 6. The methodology of the initial flaw size is based on ASME Code, Section XI Appendix L-3210.

(c) The final flaw size is based on fatigue crack growth per ASME Code Case N-809 with a constant aspect ratio. The aspect ratio for the FCG evaluation is determined per ASME Code, Section XI Appendix L.

(d) The maximum allowable end-of-evaluation flaw size is determined per ASME Code, Section XI Appendix C. The final flaw size after fatigue crack growth should be equal to or less than the maximum allowable end-of-evaluation flaw size.

(e) The allowable operating period represents the number of years (i.e., inspection interval) required for the initial flaw size to reach the maximum allowable end-of-evaluation flaw size. In cases where the allowable operating period is reported to be greater than 80 years, it should be noted that the final flaw size, after fatigue crack growth, never reached the end-of-evaluation flaw size during a maximum of 80 years of plant operation.

(f) The charging nozzle postulated initial flaw size (12.0%) is based on flaw sizes from the 2013 Edition of Section XI (Table IWB-3514-1). The 2004 Edition of Section XI allows the initial flaw size to be 12.3%; however, there will be a negligible difference in operating period since the difference between initial flaw sizes is less than 1% and there is still margin between the final flaw size and maximum allowable end-of-evaluation flaw size.

(g) The limiting location is Path P3 (upper stratification loading), surge line to hot leg nozzle safe end weld, as shown in Figure 4-10 and results in Tables 6.5 (Circumferential Flaw) and Table 6.6 (Axial Flaw) of SIA Report 1700553.402.

Table 4.3.4-4 Unit 1 Appendix L Inspections

Location	Line	Weld No.	Last ISI Inspection
Accumulator Line – Loop A Cold Leg	12-RC-22-1502	10	None
Accumulator Line – Loop B Cold Leg	12-RC-23-1502	20	None
Accumulator Line – Loop C Cold Leg	12-RC-24-1502	30	None
Safety Injection Line - Loop A	6-RC-17-1502	21	N1R27 UT - **NRI**
Safety Injection Line - Loop B	6-RC-19-1502	14	N1R23 UT - **NRI**
Safety Injection Line - Loop C	6-RC-20-1502	42	N1R26 UT- **NRI**
Surge Line	14-RC-10-2501R	37	For initial license renewal period, inspection results are available every 40 months

Table 4.3.4-5 Unit 2 Appendix L Inspections

Location	Line	Weld No.	Last ISI Inspection
Accumulator Line - Loop A Cold Leg	12-RC-422-1502	2	None
Accumulator Line - Loop B Cold Leg	12-RC-423-1502	2	None
Accumulator Line - Loop C Cold Leg	12-RC-424-1502	2	None
Safety Injection Line - Loop A	6-RC-417-1502	2	N2R20 UT NRI Limited (88%)
Safety Injection Line - Loop B	6-RC-419-1502	1A	None
Safety Injection Line - Loop C	6-RC-420-1502	2B	N2R21 UT NRI (Limited)
Surge Line	14-RC-410-2501R	3	For initial license renewal period, inspection results are available every 40 months.

4.3.5 REACTOR VESSEL INTERNALS FATIGUE ANALYSES

TLAA Description

The reactor vessel (RV) internals were designed before ASME Code, Section III, Division 1, Subsection NG was established. Therefore, no CUF values were calculated as part of the original RV internals design. However, as part of engineering evaluations to support Units 1 and 2 operations at measurement uncertainty recapture power uprate conditions, updated structural evaluations were performed for the upper and lower core plates to demonstrate that they would maintain their structural integrity at proposed power uprate conditions. The lower and upper core plates are not part of the reactor coolant system pressure boundary. As part of the structural evaluations, fatigue analyses of the upper and lower core plates were performed to the 1989 edition of ASME Code, Section III, Division 1, Subsection NG. Fatigue analyses that consider transient cycles that occur over the life of the plant constitute TLAAs. The AOR fatigue CUF results are less than 1.0 as documented in Section 4.3.5 of WCAP-18503-P.

Table 4.3.5-1 CUFs for the Reactor Vessel Internals

Component	Cumulative Usage Factor
Lower core plate	0.237
Upper core plate	0.215

TLAA Evaluation:

The MUR power uprate analyses considered various transients that were selected from the transients identified in Table 4.3.1-1.

As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) bound 80 years of plant operations. Therefore, the fatigue analyses for the RV internals remain valid for the subsequent period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The fatigue analyses for the RV internals remain valid for the subsequent period of extended operation.

4.3.6 HIGH-ENERGY LINE BREAK ANALYSIS

TLAA Description:

UFSAR, Section 3A.32.2, indicates that Class 1 pipe rupture locations have been postulated in accordance with Regulatory Guide 1.46, Protection Against Pipe Whip Inside Containment (May 1973). Regulatory Guide 1.46 guidance for Class 1 piping identifies break locations based on a limiting stress criterion and on a cumulative usage factor (CUF) criterion. The cumulative usage factor criterion applies to any intermediate locations between terminal ends were the cumulative usage factor, U, derived from the piping fatigue analysis under the loadings associated with specified seismic events and operational plant conditions exceeds 0.1. The postulations of break locations based on the fatigue criterion are TLAAs.

TLAA Evaluation:

A high energy line break is not required to be postulated at a given piping location if the design CUF calculated in accordance with ASME Code, Section III or similar USAS (ANSI) B31.7, for that location, is less than or equal to 0.1. The Class 1 piping fatigue analyses in Section 4.3.2.7, Class 1, USAS (ANSI) B31.7 Piping are based on the transient cycles listed in Table 4.3.1-1 and Section 3 of WCAP-18503-P. As shown in Table 4.3.1-1, the 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 fatigue analyses. That is, 40 years of design cycles bound the 80-year projected cycles.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The HELB evaluation uses CUF values greater than 0.1 for screening potential pipe break locations. The projected 80-year transient cycles are bounded by the 40-year design transients, as illustrated in WCAP-18503-NP, Tables 3-3 through 3-6. The original locations with CUF values equal to or less than 0.1 will remain the same for the fatigue analysis of record during subsequent period of extended operation. Therefore, this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

4.4 ENVIRONMENTAL QUALIFICATION OF ELECTRIC EQUIPMENT

TLAA Description:

Thermal, radiation, and cyclical aging analyses of plant electrical and I&C equipment, developed to meet 10 CFR 50.49, “Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants,” (Reference 1.7-8) requirements, have been identified as TLAAs. The NRC nuclear station environmental qualification (EQ) requirements in 10 CFR 50.49 require that an EQ program be established to demonstrate that certain electrical equipment located in harsh plant environments is qualified to perform applicable safety functions in those harsh environments after the effects of inservice aging. Harsh environments are defined as those areas of the plant that could be subject to the harsh environmental effects of a loss-of coolant accident (LOCA), high energy line break (HELB), or post-LOCA radiation. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification.

Environmental Qualification Program Background

10 CFR 50.49 requires that an EQ program be established to demonstrate that certain electrical equipment located in harsh plant environments will perform its safety function in those harsh environments after the effects of inservice aging. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification. Aging evaluations that qualify equipment to at least the end of the current licensed operating period are TLAAs.

10 CFR 50.49 defines the scope of equipment to be included and requires the preparation and maintenance of documentation that includes equipment performance specifications, electrical characteristics, and environmental conditions. 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 equipment functional capability. 10 CFR 50.49(e)(5) also requires equipment replacement prior to the end of designated life, unless additional life is established through ongoing qualification.

Units 1 and 2 received operating licenses in 1978 and 1980, respectively. Therefore, Unit 1 was evaluated against the DOR Guidelines and the basis for Equipment Qualification is Inspection and Enforcement Bulletin (IEB) 79-01B, “Environmental Qualification of Class 1E Equipment,” (Reference 4.8-47) and IEEE Standard 323-1974 “IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations,” (Reference 4.8-48) as codified by 10 CFR 50.49. The basis for Unit 2 is IEEE Standard 323-1974 and NUREG-0588, “Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment,” Category II, as codified by 10 CFR 50.49. IEEE 323-1974 provides the criteria for safety related equipment (electrical “Class 1E” equipment) and the basis for categorizing equipment important to safety, and defines environmental service conditions. Therefore, the EQ program includes and identifies electrical equipment that is important to safety and that could be exposed to harsh environment accident conditions, consistent with 10 CFR 50.49.

As required by 10 CFR 50.49, EQ equipment not qualified for the current license term is refurbished or replaced, or has its qualified life extended through reanalysis or ongoing qualification prior to reaching the designated life aging limits established in the evaluation. Aging evaluations for EQ equipment that specify a qualified life of at least 40 to 60 years are time-limited aging analyses (TLAAs) for subsequent license renewal.

Reanalysis of an aging evaluation to extend the qualification of equipment qualified under the program requirements of 10 CFR 50.49(e) is performed as part of the EQ program. 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).

TLAA Evaluation:

The EQ program implements the requirements of 10 CFR 50.49, as further defined and clarified by the DOR Guidelines and the basis for equipment qualification is Inspection and Enforcement Bulletin (IEB) 79-01B, NUREG-0588, Category II, and IEEE Standard 323-1974. The EQ program is viewed as an aging management program for license renewal under 10 CFR 54.3(a).

Reanalysis of an aging evaluation to extend the qualified life of equipment is performed as part of the EQ program. Important attributes for the reanalysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, corrective actions (if acceptance criteria are not met), and ongoing qualification and are addressed below. TLAA demonstration option (iii), which states that the effects of aging will be adequately managed for the period of extended operation, is chosen and the EQ program will manage the aging effects of equipment associated with the environmental qualification TLAA.

<u>Analytical Methods</u>

The analytical models used in the reanalysis of an aging evaluation are the same as those previously applied during the prior evaluation. The Arrhenius methodology is an acceptable thermal model for performing a thermal aging evaluation. An acceptable method for establishing the 80 year normal radiation dose is to multiply the 40 year normal radiation dose by 2, with the result being added to the accident radiation dose to obtain the total integrated dose for the component. A similar approach may be used for cyclical aging.

<u>Data Collection and Reduction Methods</u>

The identification of excess conservatism in electrical equipment service conditions (for example, temperature, radiation, and cycles) used in the prior aging evaluation is the primary method used for a reanalysis. Temperature data and uncertainties used in an equipment EQ evaluation should be based on plant design temperatures or on actual plant temperature data. A representative number of temperature measurements over a sufficient period of time are evaluated to establish the temperatures used in an aging evaluation. Similar methods of identifying excess conservatism in the equipment service condition evaluation may be used for radiation and cyclical aging.

Underlying Assumptions

EQ equipment aging evaluations account for environmental changes occurring due to plant modifications and events. A reanalysis demonstrates that adequate margin is maintained consistent with the original analysis in accordance with 10 CFR 50.49 requiring certain margins and accounting for the unquantified uncertainties established in the EQ aging evaluation of the equipment. Although areas within a nuclear power plant may experience actual ambient environments that are less severe than the anticipated plant design environment, in a limited number of localized areas, the actual environments may be more severe than the plant design environment considered for EQ equipment. These adverse localized environments (ALE) are addressed in an EQ reanalysis.

Acceptance Criteria and Corrective Actions

Reanalysis of an aging evaluation can be used to extend the environmental qualification of the equipment. If the qualification cannot be extended by reanalysis, the equipment is refurbished, replaced, or requalified prior to exceeding the current qualified life.

A reanalysis should be performed in a timely manner (such that sufficient time is available to refurbish, replace, or requalify the equipment if the reanalysis is unfavorable). A modification to qualified life either by reanalysis or ongoing qualification must demonstrate that adequate margin is maintained consistent with the original analysis including unquantified uncertainties established in the original EQ equipment aging evaluation.

Ongoing Qualification

When the reanalysis assessed margins, conservatisms, or assumptions do not support reanalysis (e.g., extending qualified life) of EQ equipment, the use of on-going qualification techniques including condition monitoring or condition based methodologies may be implemented. Ongoing qualification is an alternative means to provide reasonable assurance that an equipment environmental qualification is maintained for the subsequent period of extended operation. Ongoing qualification of electric equipment important to safety subject to the requirements of 10 CFR 50.49 involves the inspection, observation, measurement, or trending of one or more indicators, which can be correlated to the condition or functional performance of the EQ equipment. Ongoing qualification techniques for EQ equipment include periodic testing, inspections, mitigation, and sampling (e.g., subsequent EQ qualification testing of inservice or representative EQ equipment with established acceptance criteria and corrective actions, mitigation, replacement or refurbishment) consistent with endorsed standards and regulatory guidance.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

The effects of aging on intended functions of EQ components that are the subject of EQ TLAAs will be adequately managed for the subsequent period of extended operation under the Environmental Qualification of Electric Equipment program (Section B3.3) in accordance with 10 CFR 54.21(c)(1)(iii).

4.5 CONCRETE CONTAINMENT TENDON PRESTRESS

The Containments utilize a reinforced concrete design without the use of prestressed tendons. Therefore, loss of prestress is not applicable for the Containments.

4.6 CONTAINMENT LINER PLATE, METAL CONTAINMENTS, AND PENETRATIONS FATIGUE ANALYSIS

4.6.1 CONTAINMENT LINER PLATE

TLAA Description:

As discussed in UFSAR, Section 3.8.2.1.1, the reinforced concrete containment structure was designed to withstand all loadings and stresses anticipated during the life of the plant. The steel liner, which is attached to and supported by the concrete, functions primarily as a gas-tight membrane and transmits loads to the concrete.

The original analysis demonstrated the adequacy of the liner for the pressure, temperature, and seismic loads associated with emergency, upset, normal, and test conditions specified. Because there was no ASME Code for a steel lined concrete vessel at the time NAPS was designed, stress intensity limits and stress category definitions were determined using ASME Code, Section III, 1968 Edition, as a guide. The accumulated effects of containment liner loading conditions were evaluated in accordance with the ASME Code, Section III, Paragraph N-415, to determine the need for a detailed fatigue analysis.

The evaluation for the original 40 years of operation was based on the following design cycles:

- 1,000 cycles of operating pressure variations
- 4,000 cycles of operating temperature
- 20 cycles of design earthquake

While the numbers of pressure, temperature, and design earthquake cycles had been assumed conservatively as listed above, they were further increased proportionally to 1500, 6000, and 30 cycles, respectively, for the purpose of fatigue evaluation for 60-year plant life license renewal. Under the specified number of cycles, no detailed fatigue analysis was required as all the conditions in the ASME Code, Section III, Subsection N-415.1 were shown to be satisfied.

The containment liner material, carbon steel SA-516-Gr 60 and SA-537-Gr B, meets all six criteria in the ASME Code, Section III, Subsection N-415.1 for 60-year plant life. However, the containment liner components such as the piping penetrations, including mechanical and electrical penetrations, had not been evaluated. To qualify the plant for 80 years of operation, the containment penetrations were also evaluated, in addition to the containment liner. Because the hot penetrations (as identified in UFSAR, Table 6.2-37) and fuel transfer tube are committed to surface examinations, no fatigue waiver is required. Also, NUREG-2191, Section XI.S1, Element 4, allows Type B testing in lieu of a fatigue waiver. Type B tests are performed for the airlocks, as described in UFSAR, Section 6.2.4.4.

Table 4.6.1-1 provides data on the Containment and cold penetrations included in this evaluation.

Table 4.6.1-1 Containment & Cold Penetrations

ASTM	Material	Type	Components
SA-516 Gr 60	Carbon Steel	Containment Liner Mech Penetrations Elec Penetrations	Plates
SA-537 Gr B	Carbon Steel	Containment Liner	Plates
SA-442 Gr 60 (Alternative SA-516 Gr 60 FBX)	Carbon Steel	Mech Penetrations	Plates
SA-333 Gr 6 SA-333 Gr 3	Carbon Steel Carbon Steel	Mech Penetrations Elec Penetrations Mech Penetrations Elec Penetrations	Pipes Pipe Sleeves
SA-350 Gr LF1	Carbon Steel	Elec Penetrations	Forging
SA-182 Gr F Tp 304	Stainless Steel	Elec Penetrations	Flanges
SA-312 Tp 304 SA-312 Tp 316	Stainless Steel Stainless Steel	Mech Penetrations Mech Penetrations	Pipes (unsleeved) Pipes (unsleeved)

TLAA Evaluations:

For the initial and subsequent periods of extended operation, the design cycles and anticipated cycles were extrapolated from the original design to the values shown in Table 4.6.1-2.

Table 4.6.1-2 Containment Liner Design Load Cycles

Loading	60 years	80 years
Operating Pressure	1,500	2,000[(1)]
Operating Temperature	6,000	8,000
Design Earthquake	30	40

Note:

1. The more realistic 1500 cycles are considered in the assessment of Condition 1. The 2000 cycles of operating pressure fluctuations as projected from the original design values is overly conservative. The original fatigue waiver for the containment liner states that 1000 design cycles are five to ten times larger than the number of cycles actually expected. The operating pressure variation can be expected to occur not more than 100 times during the plant lifetime. However, for design purposes, this was conservatively increased to 1000 cycles for the original 40-year life. For initial license renewal (60 years), this was extrapolated to 1500 cycles. As noted in Westinghouse Calculation CN-SDA-II-18-007 Table 2-2, the accrued transient cycles as of 11/08/2017 for Units 1 and 2 were 58 (39.6 years) and 55 (37.2 years), respectively. The transient cycles projected for 80 years for Units 1 and 2 are 99 and 113, respectively. Even if the existing cycles are doubled to project them to 80 years of operation, there is sufficient margin in the design cycles to retain 1500 as the number of cycles used to evaluate the components for the subsequent period of extended operation (80 years).

The six conditions in ASME Code, Section III, Subsection N-415.1 were evaluated for applicable liner and penetration components as identified in Table 4.6.1-1. The design cycles shown in Table 4.6.1-2 were used to determine the need for detailed fatigue analyses. Effects of the Appendix J, Type A pressure tests were included in the evaluation.

Each of the six conditions was shown to be satisfied for each liner and penetration component. No detailed fatigue analysis is required for the containment liner or penetrations due to stress fluctuations caused by pressure, temperature, and design earthquake cycles during an 80-year plant operating term. The increase in the anticipated number of cycles due to the subsequent period of extended operation is acceptable.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The fatigue waiver analyses associated with the containment liner plate have been revised and projected to remain valid for the subsequent period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

4.6.2 METAL CONTAINMENT

Each unit has a concrete containment with a metal liner. Therefore, the topic of metal containment fatigue analysis is not applicable.

4.6.3 CONTAINMENT PENETRATIONS FATIGUE ANALYSIS

There are no TLAAs for Containment penetrations since these were not analyzed for cyclic fatigue. The penetrations are designed for a one-time load due to the collapse of the connecting pipe. All penetrations, regardless of size, are anchored in the reinforced concrete containment wall. The anchor strength is equal to the full yield strength of the pipe with regard to torsion, bending, and shear, and to the maximum possible pipe jet reaction. All stresses induced in the liner by these combinations of loadings are only those reflected by the resulting distortions in the reinforced concrete containment wall, and are minor in intensity, so loads will not be imposed on the liner, thereby preserving its integrity. The normal operating loads are much smaller than the collapse loads of the pipe, including both restrained piping system thermal expansion loads, as well as local thermal expansion loads. The stresses due to the normal operating conditions are below the endurance limit. Therefore, the penetrations will not fail due to fatigue. This evaluation remains valid for the subsequent period of extended operation.

4.7 OTHER PLANT-SPECIFIC TIME-LIMITED AGING ANALYSES

The following plant-specific safety analysis involve time-limited assumptions defined by the current operating term of the plant and are presented in this section.

- *Crane Load Cycle Limits* (Section 4.7.1)
- *Reactor Coolant Pump Flywheel Fatigue Crack Growth Analyses* (Section 4.7.2)
- *Leak-Before-Break* (Section 4.7.3)
- *Spent Fuel Pool Liner Fatigue Analysis* (Section 4.7.4)
- *Piping Subsurface Flaw Evaluations* (Section 4.7.5)
- *Reactor Coolant Pump Code Case N-481* (Section 4.7.6)
- *Cracking Associated with Weld Deposited Cladding* (Section 4.7.7)
- *Steam Generator Tube Wear Evaluation* (Section 4.7.8)

4.7.1 CRANE LOAD CYCLE LIMITS

TLAA Description:

Cranes meeting the intent of NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants” (Reference 4.8-50) are within the scope of SLR. Cranes within the scope of SLR that were designed to meet the intent of CMAA-70-1975 and have a defined service life as measured in load cycles are identified as TLAAs.

TLAA Evaluation:

Method of Evaluation - Scope

UFSAR, Section 9.6.3 indicates the load handling systems consistent with NUREG-0612. For these load handling systems, the following table summarizes the design specifications, the service class, and reference sources.

Table 4.7.1-1 Design Summary

Load Handling System	Design Specification	Service Class
Reactor Containment Polar Cranes	EOCI-61[1]	A
Fuel Building Movable Platform	CMAA Spec 70[4]	A
Fuel Building Trolley	EOCI specification in affect at time of manufacture[2]	A
Reactor Containment Annulus Hoists	CMAA Spec 70	A
Auxiliary Building Monorails (Elevations 259' - 6' and 274')	CMAA Spec 70	A
RHR Pump Monorails	ANSI B30.11-1980 (Reference 4.8-52)[3]	N/A

Notes:

1. As stated in UFSAR, Section 9.6.4.7 and the Technical Evaluation Report (Reference 4.8-58) the reactor containment polar cranes meet all of the "14 revised requirements of CMAA-70."
2. The Technical Evaluation Report (Reference 4.8-58) concludes that design of the cranes is consistent with the criteria of Guideline 7 (i.e., NUREG-0612, Section 5.1.1(7)). Since the fuel building trolley was designed to the EOCI specification which was superseded by CMAA-70, and since the design of the fuel building trolley was evaluated as being consistent with Guideline 7, the fuel building trolley is identified as having a TLAA requiring evaluation for SLR.
3. The RHR pump monorails were re-designed in 1989 to ANSI B30.11-1980 (References 4.8-52 and 4.8-60) which does not include requirements for cyclical loads. Therefore, the RHR pump monorails are not identified as having a TLAA requiring evaluation for SLR.
4. UFSAR, Section 9.1.4.4.5.

Methodology of Analysis - Acceptance Criteria

CMAA-70 (1975) presents the bounding number of load cycles and allowable stress range for each service class and stress category. These design criteria define the acceptable service limits for the TLAA. All load handling systems within the scope of this evaluation were designed to Service Class A requirements.

The conclusion reached in the technical evaluation of the six-month response to NRC Generic Letter 81-07 is that cranes and other lifting devices subject to NUREG-0612, satisfy the design intent of CMAA-70. CMAA-70 provides guidance regarding fatigue, but EOCI Specification 61 does not explicitly address fatigue failure. The following paragraph describes the method for selecting the service class from CMAA Specification 70 that corresponds to the service class originally specified from EOCI Specification 61 to be used with CMAA Specification 70 (1975), Table 3.3.3.1.3-1 to identify the applicable number of load cycles for service class.

The plant specifications for the reactor containment polar cranes and the fuel building trolley require design to EOCI Specification 61 Service Class A defined as follows:

> "Class A - (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 plant specifications for the reactor containment annulus hoists, auxiliary building monorails, and fuel building movable platform require design to CMAA Specification 70, Class A1. The corresponding service class in CMAA Specification 70 (1975) is Class A1 (standby) service, defined as follows:

> "Class A1 - (Standby Service) - This service class covers cranes used in installations such as; power houses, public utilities, turbine rooms, motor rooms and transformer stations, where precise handling of valuable machinery at slow speeds with long idle periods between lifts is required. Capacity loads may be handled for initial installation of machinery and for infrequent maintenance."

Based on the comparison of service classes described in the original design specification (EOCI Specification 61) to CMAA Specification 70 (1975), for the reactor containment polar cranes and the fuel building trolley, the applicable CMAA Specification 70 service class is 'A'.

The reactor containment annulus hoists, auxiliary building monorails, and the fuel building movable platform were designed for CMAA Specification 70 Service Class A (see Table 4.7.1-1).

Reactor Containment Polar Crane Evaluation:

The reactor containment polar cranes were designed to meet the intent of Class A (Standby) Service. The CMAA Specification 70 Class A service design includes consideration of 100,000 load cycles during the life of the crane. Recurring loads associated with the reactor containment polar cranes that are in excess of 5% of crane capacity are presented in Table 4.7.1-2 together with infrequent loads associated with initial construction and major maintenance. The total projected number of these load cycles is approximately 32,182 for each unit over the 80-year life of the plant. Since the total number of expected load cycles is considerably less than the maximum number of load cycles of 100,000 considered for Service Class A in CMAA Specification 70, the TLAA for the reactor containment polar cranes remains valid.

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Table 4.7.1-2 Reactor Containment Polar Crane Operation

Heavy Load Description[1]	Approximate Load Weight (tons)[1]	Frequency	Number of Refuel Cycles[2]	Number of Lifts Over Plant Life
Reactor vessel head with lifting rig	135.9	2/refuel cycle	53	106
Control Rod Drive (CRD) missile shield	33.3	2/refuel cycle	53	106
Reactor vessel upper internals and lifting rig	60.7	2/refuel cycle	53	106
Reactor vessel lower internals and lifting rig[3]	138.7	2/refuel cycle	53	106
Reactor coolant pump motor	39	2/refuel cycle	53	106
Reactor cavity seal ring	8.5	2/refuel cycle	53	106
Reactor Vessel Inspection Tool	5.0	2/refuel cycle	53	106
Reactor Containment Recirculation Fan	2.8	2/refuel cycle	53	106
Containment floor concrete hatches (24 total for each unit) [4]	Various weights up to 15 tons	48/refuel cycle	53	2,544
Filter Cask 1[5]	7.2	10/refuel cycle	53	530
Filter Cask 2[5]	2.4	10/refuel cycle	53	530
Filter Cask 3[5]	2.4	10/refuel cycle	53	530
Large equipment placement lifts - Initial construction and major equipment replacement. Lifts in support of needed maintenance or inspections.	Various	500 over life	N/A	500
Historical lifts (20,000 estimated to support refueling for first 60 years as presented in initial license renewal application, proportioned to 80 years.)[6]				26,700
80-year total estimated load lifts (each unit)				32,182

Notes:

1. Load descriptions and weights per UFSAR, Table 9.6-1 and the Technical Evaluation Report (Reference 4.8-58)) (excluding loads less than 5% of crane capacity).
2. Unit 1 has completed 27 refuel cycles through Fall 2019. Unit 2 has completed 26 refuel cycles through Spring 2019. Total projected 18 month cycles through 80 years is 53 for each unit.
3. RV lower internals are not removed each refueling outage. However, to include removal of the lower internals for reasons other than inservice inspection, this evaluation identifies two lifts each refueling cycle.
4. Number and weight of concrete floor hatches were identified from site procedures,
5. Filter casks may be used in containment. 10 lifts per cycle is conservatively assumed.
6. Total lifts over 80 years based on conservative 60 year lifts of < 20,000 cycles (Reference 4.8-62)

Fuel Building Movable Platform Evaluation:

The fuel building movable platform is shared by both units and is used to move the spent fuel gates, to load and unload fuel and to lift spent-fuel assemblies. The fuel building movable platform with hoists in the fuel building is a wheel-mounted motor-driven platform with two overhead electric hoists for lifting new and spent-fuel assemblies. The platform spans the spent-fuel pit and may be maneuvered over the fuel pit, the fuel transfer canals, and the new-fuel handling and storage area in the fuel building. (UFSAR, Sections 9.1.2, and 9.1.4)

Of the cranes within the scope of this review, the fuel building movable platform is identified as the most frequently used. The fuel building movable platform crane can be expected to make 25,000 lift cycles to support the refueling of both units over a 60-year period. This does not include the cycles required to load new fuel into the spent fuel pool, the various fuel shuffles performed by operations support, the various fuel inspections by fuel vendors, and the cycles required to load the spent fuel casks. In order to account for the various lifts, the crane was identified as making a total of 50,000 lifts for the 60-year period evaluated for initial license renewal (References 4.8-62, Attachment 5). This value is projected to 66,700 lifts for 80 years. Since the total number of expected load cycles is considerably less than the maximum number of load cycles of 100,000 considered for Service Class A in CMAA Specification 70, the TLAA for the fuel building movable platform remains valid.

Table 4.7.1-3 Fuel Building Movable Platform

Heavy Load Description	Approximate Load Weight (tons)	Number of Lifts Over Plant Life
Spent Fuel Cavity Gate	1.8	See Note 1
Fuel Assemblies	1	
Other[1]		
80-year total estimated load lifts[1]		66,700

Note:

1. Total lifts over 80 years based on conservative 50,000 lift cycles for 60 years (Reference 4.8-62).

Fuel Building Trolley Evaluation:

The 125-ton capacity fuel building trolley is used to handle the spent-fuel cask. The fuel building trolley runs on fixed rails spanning the west end of the spent-fuel pit. (Reference UFSAR, Section 9.1.4.4.12)

Based on the maximum number of 20,000 load cycles expected for 60 years (References 4.8-62), the total projected number of load cycles is approximately 26,700 over the 80-year life of the plant. Since the total number of expected load cycles is considerably less than the maximum number of load cycles of 100,000 considered for Service Class A in CMAA Specification 70, the TLAA for the fuel building trolley remains valid.

Table 4.7.1-4 Fuel Building Trolley

Heavy Load Description	Approximate Load Weight (tons)	Number of Lifts over Plant Life
Spent Fuel Cask (incl. fuel, lift beam, and lid)	125	See Note 1
Spent Fuel Container and Cask	not provided	
Irradiated Specimen Cask	5.7	
Fuel Pool Gate	2.1	
Other[1]		
80-year total estimated load lifts[1]		26,700

Note:

1. Total lifts over 80 years based on conservative 60 year lifts of < 20,000 cycles (Reference 4.8-62).

Reactor Containment Annulus Hoists Evaluation:

The reactor containment annulus hoists are each mounted on a monorail located at Elevation 323'-4” for Units 1 and 2. The hoists are used to maneuver equipment during shutdown (Reference UFSAR, Section 6.2.1.2.13). The reactor containment annulus hoists are designed for Class A (Standby) Service. The CMAA Specification-70 Class A service design includes consideration of 100,000 load cycles during the life of the crane.

For initial license renewal, the 60-year load cycles for the reactor containment annulus hoists were identified as being bounded by the 60-year load cycles identified for the shared fuel building movable platform. Therefore, the 50,000 load cycles assumed for 60 years is projected to 66,700 cycles for the reactor containment annulus hoists. Since the reactor containment annulus hoists are only used to maneuver equipment during shutdown and are not shared by both units, the use of the projected cycles for the fuel building movable platform is conservative and reasonable. Since the

66,700 assumed load cycles is considerably less than the maximum number of load cycles of 100,000 considered for Service Class A in CMAA Specification 70, the TLAA for the reactor containment annulus hoists remains valid.

Table 4.7.1-5 Reactor Containment Annulus Hoists

Heavy Load Description	Approximate Load Weight (tons)	Number of Lifts over Plant Life
Various loads up to rated capacity (5 tons)	Up to 5 tons.	See Note 1
80-year total estimated load lifts (Unit 1 / Unit 2)		66,700

Note:

1. Total lifts over 80 years based on conservative 50,000 lifts cycles for 60 years (Reference 4.8-62).

Auxiliary Building Monorails Evaluation:

The auxiliary building monorails within the scope of this evaluation include a monorail at elevation 259'-6" and a monorail at elevation 274'. These monorails are used to lift filter casks 1, 2, and 3 during filter removal and installation for the reactor coolant filters, seal water return filters, seal water injection filters, reactor coolant letdown filters, boron recovery filters, boron evaporator filters, refueling purification filters, and pumps to gas stripper filters. In addition, the auxiliary building monorails are used to move concrete floor/wall plugs and various other heavy loads in the auxiliary building. Historical work orders associated with the identified components were reviewed to identify past work requiring lifting of heavy loads and to project 80-year total accumulated lifts. In order to account for other miscellaneous lifts not identified to work orders associated with the above identified components, and to account for multiple lifts during completion of each work order, each work order identified was assigned 8 full capacity lifts. In addition, although the separate lifts needed for the identified work orders were performed by both monorails, the total projected lifts are conservatively assumed for each monorail. Based on this review, 13,282 lifts are projected for each monorail for 80 years. Since the total number of expected load cycles is considerably less than the maximum number of load cycles of 100,000 considered for Service Class A in CMAA Specification 70, the TLAA for the auxiliary building monorails remains valid.

Table 4.7.1-6 Auxiliary Building Monorails (Elevations 259’-6" and 274’)

Heavy Load Description	Approximate Load Weight (tons)	Number of Lifts over Plant Life
Filter Cask 1	7.2	See Note 1
Filter Cask 2	2.4	
Filter Cask 3	2.4	
Circular Plugs (18 total, both elevations)	1.2	
Charging Pump cubicle wall panel w/counterweight	3.8	
Nonregenerative Heat Exchanger	4.25	
Concrete floor plugs (42 total, 259’-6” elevation)	Various weights up to 8.15 tons	
Concrete floor plugs (27 total, 274’ elevation)	Various weights up to 12.5 tons	
Various loads up to rated capacity (8 tons for 259’ level and 12 tons for 274’ level)	Up to 12 tons	
80-year total estimated load lifts (each monorail)[1]		14,145

Note:

1. Total lifts over 80 years based on work history projected to 80 years (see Table 4.7.1-7).

The following table summarizes the projected 80 year lifts associated with each component identified by the maintenance procedures for performing the various maintenance tasks requiring use of the auxiliary building monorails:

Table 4.7.1-7 Evaluation of Auxiliary Building Monorails - Projected 80 Years Lifts

Component Description	Projected 80 Years Lifts
Reactor Coolant Filters (2)	5481
Seal Water Return Filters (2)	100
Seal Water Injection Filter (4)	2433
Reactor Coolant Letdown Filters (2)	736
Boron Recovery Filters (2)	53
Boron Evaporator Filters (2)	50
Refueling Purification Filters (2)	2574
Gas Stripper Filters (2)	156
Nonregenerative Heat Exchangers (2)	127
Charging Pumps and Charging Pump Wall Panels (6)	2435
Total Projected 80 Year Lifts	14,145

TLAA Disposition: 10 CFR 54.21(c)(1)(i):

The load cycle analyses for the reactor containment polar cranes, fuel building movable platform, fuel building trolley, reactor containment annulus hoists, and auxiliary building monorails have been demonstrated to remain valid through the subsequent period of extended operation.

The total projected load cycles for the cranes identified in Table 4.7.1-1 subject to TLAA evaluation based on past and future use is summarized as follows:

Table 4.7.1-8 Evaluation Summary

Load Handling System	CMAA Service Class	Maximum Number of Load Cycles	Projected Number of Load Cycles for 80 Years	Valid for 80 Years
Unit 1 Reactor Containment Polar Crane	Class A	100,000	32,182	Yes
Unit 2 Reactor Containment Polar Crane	Class A	100,000	32,182	Yes
Fuel Building Movable Platform	Class A	100,000	66,700	Yes
Fuel Building Trolley	Class A	100,000	26,700	Yes
Unit 1 Reactor Containment Annulus Hoist	Class A	100,000	66,700	Yes
Unit 2 Reactor Containment Annulus Hoist	Class A	100,000	66,700	Yes
Auxiliary Building Monorail (259’ level)	Class A	100,000	14,145	Yes
Auxiliary Building Monorail (274’ level)	Class A	100,000	14,145	Yes

4.7.2 REACTOR COOLANT PUMP FLYWHEEL FATIGUE CRACK GROWTH ANALYSES

TLAA Description:

The reactor coolant pump (RCP) flywheel is discussed in UFSAR, Section 18.3.5.2, which references WCAP-14535A, “Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination” (Reference 4.8-63).

The RCP flywheel inspection is specified in Technical Specification 5.5.6. NRC Letter dated June 15, 2005, “North Anna Power Station, Units 1 and 2 - Issuance of Amendments to Extend the Inspection Interval for Reactor Coolant Pump Flywheels (TAC Nos. MC4213 and MC4214)” (Reference 4.8-64), amended the Technical Specification to extend the inspection interval for the RCP flywheel from 10 years to 20 years, consistent with the evaluation in WCAP-15666-A, “Extension of Reactor Coolant Pump Motor Flywheel Examination” (Reference 4.8-65).The inspection is a qualified in place UT examination over the volume from the inner bore of the RCP flywheel to the circle of one half the outer radius or a surface examination (magnetic particle testing and/or liquid penetrant testing) of the exposed surfaces defined by the volume of the disassembled RCP flywheels. No recordable indications have been detected for the examinations performed on the RCP flywheel over the service life that could invalidate the existing analysis.

Considering the RCP flywheel probability of failure is part of the current licensing basis and is used to support safety determinations, and the probability of failure was based upon 60-year assumptions and 6,000 pump starts and stops, this fatigue analysis has been identified as a TLAA requiring evaluation for the subsequent period of extended operation.

TLAA Evaluation:

RCP start and stop cycles are projected in Table 4.7.2-1.

Table 4.7.2-1 RCP Start/Stop Cycle Projections for 80 Years

Heatup/Cooldown Cycles (Table 4.3.1-1)	Estimated RCP Start/Stop Cycles per Heatup/Cooldown Cycle[a]	Total Projected RCP Start/Stop Cycles for 80 Years
200	6	1,200

Note:

(a) The estimate of six start/stop cycles is based on operator interviews and is less than 100 start/stop cycles per calendar year assumed in WCAP-15666-A demonstrating operational margin.

During normal operation, the RCP flywheel possesses sufficient kinetic energy to potentially produce high energy missiles in the unlikely event of failure. Conditions which 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 RCP flywheel bore keyway.

An evaluation of the probability of failure over the subsequent period of extended operation was performed. The evaluation is documented in PWROG-17011-NP-A, "Update for Subsequent License Renewal: WCAP-14535A, 'Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination', and WCAP-15666-A, 'Extension of Reactor Coolant Pump Motor Flywheel Examination'" (Reference 4.8-66). PWROG-17011-NP-A confirms that the analysis under WCAP-14535A and WCAP-15666-A, justifying inspection of the RCP flywheel once every 20 years, remains appropriate for application up to 80 years of operation. The NRC safety evaluation of PWROG-17011-NP-A confirms that there are no limitations or conditions for the Westinghouse RCP flywheels.

The fatigue crack growth calculations assumed 6,000 cycles of RCP start and stop for the 80 year plant life which bounds the projected cycle counts of 1,200 start/stops. Dominion Energy confirms that 6,000 cycles for 80 years of operation applies to Units 1 and 2. The fatigue crack growth is negligible over an 80-year life of the RCP flywheel, even when assuming a large initial crack length.

The evaluation demonstrates that the RCP flywheel design has a high structural reliability with a very high flaw tolerance and negligible fatigue flaw crack extension over an 80-year service life.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

The RCP flywheel fatigue analysis has been demonstrated to remain valid through the subsequent period of extended operation.

4.7.3 LEAK-BEFORE-BREAK

TLAA Description:

The aging effect identified in this TLAA is thermal aging of CASS material resulting in embrittlement, that is, a decrease in the ductility, impact strength, and fracture toughness and an increase in hardness and tensile strength of the material. This TLAA uses fully aged fracture toughness properties.

The fatigue crack growth (FCG) evaluation performed in WCAP-11163-P, Revision 2, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for North Anna Units 1 and 2 Nuclear Power Plants for the Subsequent License Renewal Program (80 Years) Leak-Before-Break Evaluation" (Reference 4.8-67), is a defense in depth evaluation to demonstrate that small surface flaws do not become through wall flaws over the life of the plant. The FCG evaluation was based on a generic model with representative design transient and cycles that are applicable.

10 CFR 50, Appendix A, Criterion 4, allows for the use of leak-before-break (LBB) methodology for excluding the dynamic effects of postulated ruptures in reactor coolant system piping. The

fundamental premise of the LBB methodology is that the materials used in nuclear power plant piping are sufficiently tough that even a large through wall crack would remain stable and would not result in a double ended pipe rupture.

UFSAR, Section 18.3.5.3 and 3.6.2.4 discuss LBB, which applies only to the reactor coolant system (RCS) primary loop piping.

To maintain the LBB design basis for the plant, the LBB evaluation needed to be performed for an 80-year plant life.

TLAA Evaluation:

WCAP-11163, “Technical Bases for Eliminating Large Primary Loop Pipe Rupture as a Structural Design Basis for North Anna Units 1 and 2,” (Reference 4.8-68), and WCAP-11163, Supplement 1, “Additional Information in Support of the Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for North Anna Units 1 and 2,” (Reference 4.8-69), demonstrated that the dynamic effects of postulated ruptures in primary coolant loop piping in pressurized water reactors (PWRs) can be excluded from the design basis for Units 1 and 2. The methodology of WCAP-11163 and its supplement is consistent with the original, generic work performed as the basis of Generic Letter 84-04, “Safety Evaluation of Westinghouse Topical Reports Dealing with Elimination of Postulated Pipe Breaks in PWR Primary Main Loops” (Reference 4.8-70).

Over the years, subsequent LBB evaluations were performed, in order to maintain an updated and applicable analysis of record; the Replacement Steam Generator project, Reactor Coolant Pump Support Modification project, Initial License Renewal project (60 years), 2% Power Uprate project, Measurement Uncertainty Recapture project, FSWOL and Weld Inlay projects.

WCAP-11163-P, reevaluates all the above inputs to ensure that the existing LBB evaluation conclusions remain applicable for the 80-year subsequent period of extended operation.

The analysis documented the plant specific geometry, loading, and material properties used in the fracture mechanics evaluation. Mechanical properties were determined at operating temperatures. Since the piping systems include cast austenitic stainless steel, fracture toughness considering thermal aging was determined for each heat of material. Fully aged fracture toughness properties were used for the LBB evaluation. The fully aged condition is applicable for plants operating beyond 30 Effective Full Power Years (EFPY) for the CF8A materials and 15 EFPY for the CF8M materials (elbow fittings for Units 1 and 2). As of June 2018, Units 1 and 2 were operating at 32.1 and 30.5 EFPY, respectively.

The updates performed for WCAP-11163-P included a recalculation of delta ferrite and fracture toughness properties based on NUREG/CR 4513, “Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems” (Reference 4.8-71). As discussed in WCAP-18506-P, “Flaw Tolerance Evaluation for Susceptible Reactor Coolant Loop Cast Austenitic Stainless Steel Piping Components for North Anna Units 1 and 2" (Reference 4.8-72), one delta ferrite value in the Unit 1 crossover leg exceeded the 25% threshold and required a plant specific evaluation.

FCG analysis is not a requirement for the LBB analysis since the LBB analysis is based on the postulation of a through-wall flaw, whereas the FCG analysis is performed based on the surface flaw. In addition, the staff has previously indicated in the Modification of GDC 4 that, “the Commission deleted the fatigue crack growth analysis in the proposed rule. This requirement was found to be unnecessary because it was bounded by the crack stability analysis.”

Nevertheless, the FCG in WCAP-11163-P was documented and retained to keep with historical precedence to demonstrate that small surface flaws will not result in a through-wall flaw over the design life of the plant. The aspect ratio and crack size for the postulated initial cracks were for a typical flaw shape and large enough to be detectable in inspections. Various initial flaw depths were considered in the FCG analysis to demonstrate that small NDE detectable flaw sizes would be acceptable for the life of the plant (i.e. will not grow to the become complete through-wall).

The intent of FCG in the LBB analysis was not to use initial flaw depths that are larger than the Acceptance Tables of ASME Code, Section XI, IWB-3410-1, but rather to show a defense in-depth fatigue crack growth based on small flaw sizes that are detectable based on NDE examination techniques, which would not become through-wall flaws over the design life of the plant.

The analysis provides a fracture mechanics demonstration of reactor coolant system (RCS) primary loop integrity consistent with the NRC position for exemption from consideration of dynamic effects noted in NUREG-0800, Section 3.6.3, “Leak-Before-Break Evaluation Procedures” (Reference 4.8-73). The analysis in WCAP-11163-P justifies the elimination of RCS primary loop pipe breaks from the structural design basis for the 80-year subsequent period of extended operation 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 Units 1 and 2 steam generator inlet nozzles and steam generator outlet nozzles. The alloy 82/182 welds are susceptible to Primary Water Stress Corrosion Cracking (PWSCC).

   To mitigate PWSCC due to the existence of Alloy 82/182, either weld inlay or FSWOL has been applied to the Unit 1 steam generator inlet nozzles, and Unit 2 steam generator inlet nozzles and steam generator outlet nozzles. Therefore, for those locations, no further consideration of PWSCC effects is required for the subsequent period of extended operation. Evaluation of the Unit 1 steam generator outlet nozzles alloy 82/182 welds is updated for the subsequent period of extended operation, the results are documented in WCAP-11163-P, Revision 1, and found to be acceptable.

b. For local and global failure mechanisms, all locations are evaluated using the cast stainless steel material properties (A351-CF8A and A351- CF8M) which present a limiting condition due to the thermal aging effects. The cast stainless steel fracture toughness properties also present a limiting condition when compared to the fracture toughness properties of the Alloy 82/182 and 52/152 dissimilar metal weld materials found in Units 1 and 2 steam generator inlet and outlet nozzle welds.

For the 80-year subsequent period of extended operation, for the unmitigated locations at Unit 1 steam generator outlet nozzles, the LBB has been reevaluated not only due to thermal aging effects but also by considering alloy 82/182 material properties that include the appropriate PWSCC crack morphology parameter.

For the mitigated dissimilar metal weld locations, including the Unit 1 steam generator inlet nozzles with applications of SWOL program and the Unit 2 steam generator inlet nozzles and steam generator outlet nozzles with weld inlay, LBB has been reevaluated by additionally considering both Alloys 52/152 and 82/182 and demonstrating that the material properties of the thermally aged CASS base metal are more limiting. Evaluation of the RCS piping considering the thermal aging effects for the 80-year subsequent period of extended operation and also the use of the most limiting fracture toughness properties ensures that each materials profile is appropriately bounded by the LBB results.

c. Water hammer should not occur in the RCS piping because of system design, testing, and operational considerations.
d. The effects of low and high cycle fatigue on the integrity of the primary piping are negligible.
e. Ample margin exists between the leak rate of small stable flaws and the capability of the Units 1 and 2 reactor coolant system pressure boundary Leakage Detection System.
f. Ample margin exists between the small stable flaw sizes of item (e) and larger stable flaws.
g. 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 e, f, and g above.

Based on the above, the LBB conditions and all recommended margins are satisfied for the reactor coolant system primary loop piping. It is therefore concluded that dynamic effects of reactor coolant system primary loop pipe breaks need not be considered in the structural design basis for Units 1 and 2 for the 80-year subsequent period of extended operation.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The assessment performed in WCAP-11163-P, determined that the crack stability results, fracture toughness, and fatigue crack growth results are acceptable for 80-year subsequent period of extended operation. Therefore, the LBB analysis is projected through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

4.7.4 SPENT FUEL POOL LINER FATIGUE ANALYSIS

TLAA Description:

The spent fuel pool liner located in the Fuel Building is needed to prevent a leak to the environment. A design calculation has been identified which documents that the spent fuel pool design meets the general industry criteria of ASME Code, Section III, 2010 Edition, Subsections NB-3222.2, NB-3222.4, and NB-3228.5 (Reference 4.8-74). The calculation includes a fatigue analysis to add a further degree of confidence.

TLAA Evaluation:

As discussed in UFSAR, Section 9.1.3.5, the fuel pit (also known as spent fuel pool) water temperature is monitored, and an alarm in the control room alerts the operator if this temperature exceeds 140°F.

As discussed in UFSAR, Section 9.1.3.1, the spent fuel pool cooling system has the capability to:

1. Maintain the temperature of the fuel pit water below 140°F during a normal core offload condition commencing 100 hours after shutdown. A normal core offload condition is a planned offload of up to a full core. The most limiting condition for normal core offload is a full core offload following refueling of the other unit.

2. Maintain the temperature of the spent fuel pool water below 170°F during an abnormal core offload condition commencing 100 hours after shutdown. An abnormal core offload is an unplanned offload of up to a full core. The most limiting condition for an abnormal core offload is an unplanned full core offload following back-to-back refuelings of both units.

   The spent fuel pool liner was designed for three conditions:

   Condition 1: Normal core offload, maximum temperature = 140°F

   Condition 2: Abnormal core offload, maximum temperature = 170°F

   Condition 3: Faulted Condition, maximum temperature = 212°F

The projected number of thermal cycles corresponding to each of these conditions is reflected in Table 4.7.4-1 below.

Table 4.7.4-1 Spent Fuel Pool Liner Thermal Cycles

Condition	Projected 60 Years	Projected 80 Years	Allowable
1	81	108	1200
2	8	11	20
3	1	1	9

The projected number of thermal cycles corresponding to Conditions 1 and 2 for an 80-year plant operating term were increased proportionally to estimate the number of cycles during 80 years plant life. Since the faulted Condition 3 (with the maximum temperature of 212°F) is an extreme case which is not expected to happen during the subsequent period of extended operation, the number of cycles for Condition 3 was not proportionally increased and only a single cycle was considered for faulted Condition 3. Considering the most conservative case of fatigue effects, the maximum allowable numbers of cycles were estimated in the original calculation as 1200, 20, and 9 for Conditions 1, 2, and 3, respectively.

The thermal stresses in the spent fuel pool liner due to conservatively postulated thermal transients during 80-year plant life satisfy the requirements of the ASME codes. The specified numbers of temperature cycles involve large margins because they are conservatively projected based on the number of cycles for 60-year plant life. Therefore, fatigue criteria are satisfied and no compensatory action is required.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

Fatigue analysis associated with the spent fuel pool liner has been projected to the end of the subsequent period of extended operation.

4.7.5 PIPING SUBSURFACE FLAW EVALUATIONS

TLAA Description:

Piping subsurface flaw evaluations are discussed in UFSAR, Section 18.3.5.5. Calculations have been identified that address piping subsurface indications detected by inspections on the safety injection piping, main steam and feedwater piping, and generically for the Seismic Category I piping. The indications in the safety injection, main steam and feedwater piping were originally discovered during the inservice inspections and evaluated in 1984 based on a fracture mechanics assessment in accordance with ASME Code, Section XI. ASME Code, Section XI provides the acceptance criteria for various flaw orientations, locations, and sizes. The calculations determined the number of thermal cycles required for the flaws to reach an unacceptable size.

TLAA Evaluation:

The piping subsurface indication calculations were reassessed for 80 years of operation to demonstrate that the indications discovered in 1984 remain acceptable for the subsequent license renewal period of extended operation based on the latest fracture mechanics methodology. The 80-year calculations described in WCAP-18503-P were based on the fatigue crack growth equations of ASME Code, Section XI, Appendix A and Appendix C.

The investigation and analysis considered three topics which were updates to stresses, changes in stress intensity factor calculations, and changes in fatigue crack growth rates since the original analyses performed in 1984 for the safety injection, main steam and feedwater lines. Stress intensity factors were updated to be consistent with ASME Boiler and Pressure Vessel Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," 2013 Edition.

Table 4.7.5-1 Piping Subsurface Indication Allowable and Estimated Cycles

Item	Line	Stresses (psi)	Allowable Cycles[1,2,4]	Estimated Cycles[5] for 80 Years
1	Unit 1: 8"/Safety Injection Piping	30,000	6,170	200
2	Unit 1: 32"/Main Steam Piping	36,900	3,512	200
	Unit 1: 16"/Feedwater Piping	31,100	4,382	200
3	Unit 2: 6"/Feedwater Piping	31,100	2,327	200
4	Units 1 & 2: Seismic I Category Piping	32,600	42,508[3]	200

Notes:

1. The latest stress intensity factor (Ki) currently used in the industry based on API-579-1 was applied to the evaluation.
2. Allowable cycles were reduced from original analysis.
3. Allowable cycles are calculated based on the yield stress of 32,600 psi, which is higher than the stress of 27,700 psi used in the UFSAR, (Section 3C.2.7.8). When the stress the stress of 27,700 psi (plus 2,250 psi of crack face pressure), the allowable cycles are 70,397. Note that with the use of the yield stress, the effect of the crack face pressure is already covered and does not need to be considered separately, although it adds conservatism when adding it on top of the yield stress.
4. Refer to WCAP-18503-NP, Table 5-2.
5. Note that the 200 cycles are full stress cycles consistent with the number of times the plant can be heated up.

The calculated allowable cycles were all well above the estimated cycles that are expected to occur for these lines in an 80-year life of Units 1 and 2 (allowable cycles are 10 to 30 times greater than estimated cycles for Items 1 through 3, and at least 200 times greater than the estimated cycles for item 4). Therefore, there is no need for any future repair, replacements, or re-evaluations for these particular subsurface indications.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The piping subsurface flaws detected during inservice inspections in 1984 have been re-evaluated for the 80-year life and shown to have allowable cycles well above the estimated cycles expected for the piping components of interest and are therefore satisfied for the subsequent period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

4.7.6 REACTOR COOLANT PUMP CODE CASE N-481

TLAA Description:

The reactor coolant pumps (RCPs) are Westinghouse model 93A with SA-351, Grade CF-8 pump casings. Periodic volumetric inspections of the welds of the reactor coolant system (RCS) primary loop pump casings of commercial nuclear power plants were specified by ASME Code, Section XI. The inspections result in large radiation exposure (man-rem), which is a personnel safety concern. Since the pump casings were inspected prior to being placed in service, and no significant mechanisms exist for crack initiation and propagation, it has been concluded that the inservice volumetric inspection can be replaced with an acceptable alternate inspection. In recognition of this, ASME Code Case N-481, “Alternative Examination Requirements for Cast Austenitic Pump Casings” (Reference 4.8-75), provides an alternative to the volumetric inspection requirement. ASME Code Case N-481 allows the replacement of volumetric examinations of RCS primary loop pump casings with fracture mechanics-based integrity evaluations (Item (d) of the code case) supplemented by specific visual examinations.

The initial evaluation included in WCAP-13045, “Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply System” (Reference 4.8-76), has been updated to validate saturated fracture toughness values are used for assessment of the integrity of the pump casing through the subsequent period of extended operation. Validation of this fracture mechanics evaluation was specified in ASME Code Case N-481 as a condition to conduct visual examinations in lieu of the volumetric inspections specified in ASME Code, Section XI.

TLAAs related to ASME Code Case N-481 have been identified: thermal aging of cast austenitic stainless steel (CASS) and its consequence on fatigue crack growth. ASME Code Case N-481 is discussed in UFSAR, Section 18.3.5.6.

TLAA Evaluation:

ASME Code Case N-481 allowed the replacement of volumetric examination of RCS primary loop pump casings with a safety and serviceability fracture mechanics-based integrity evaluation supplemented by specific visual inspections. WCAP-13045 presents the integrity evaluation that was performed to demonstrate compliance with ASME Code Case N-481. WCAP-13044, “Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply System” (Reference 4.8-77), presents the non-proprietary information in WCAP-13045. The fracture toughness properties are presented in WCAP-13045.

Since the time WCAP-13045 was published, the ASME Code Table Category B-L-1, Item B12.10, has been updated to be consistent with the guidance of ASME Code Case N-481 in mandating visual inspections of the primary loop pump casings. In March 2004, ASME Code Case N-481 was annulled by ASME, and the information in the code case was implemented into the 2008 addenda of ASME Code, Section XI. However, the technical basis of the WCAP-13045 report was based on experience with evaluations performed for an assumed 40-year life. With subsequent license renewal extending plant service life to 80 years, the integrity evaluations in WCAP-13045 needed to be reviewed and confirmed applicable for 80 years of operation.

The fracture mechanics integrity assessment in PWROG-17033-NP-A, “Update for Subsequent License Renewal: WCAP-13045, 'Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems'” (Reference 4.8-78), as well as the requirements of ASME Code Case N-481 (now incorporated into the ASME Code, Section XI) were reaffirmed to demonstrate that the visual inspections, in lieu of volumetric inspections, for pump casings remain valid for an 80-year life. As stated in its safety evaluation, the NRC has determined that PWROG-17033-NP-A, demonstrates structural integrity of the Westinghouse-designed RCP casings for the subsequent period of extended operation (80 years) based on the crack stability analysis and FCG analysis. The NRC concluded in its safety evaluation that PWROG-17033-NP-A, is acceptable for generic use to address the time-limited aging analysis of the RCP casing integrity to satisfy the requirements of 10 CFR 54.21(c)(1)(i).

As stated in PWROG-17033-P-A, there are four criteria that must be met for PWROG-17033-P-A to be applicable to a given plant and to satisfy the requirements of 10 CFR 54.21(c)(1). These conditions for the plant-specific use of PWROG-17033-P-A are summarized as follows:

1. The licensee must confirm its RCPs are Westinghouse-designed models.

   A site-specific evaluation demonstrating applicability of WCAP-13045 was performed and documented in WCAP-15555 for initial license renewal confirming the NAPS Units 1 and 2 RCPs are the Westinghouse Model 93A design.

2. The licensee must confirm that the Westinghouse-designed RCP is either a Model 63, Model 70, Model 93, Model 93A, Model 93A-1, Model 93D, Model 100A, or Model 100D, and fabricated with SA-351 CF8 or CF8M material.

   A site-specific evaluation demonstrating applicability of WCAP-13045 was performed and documented in WCAP-15555. The NAPS Units 1 and 2 RCP casings are the Westinghouse Model 93A design which consist of SA-351 CF8 cast stainless steel with dimensions representative of those provided in Figure 3-4 of WCAP-13045.

3. For the crack stability analysis, the licensee must confirm that the screening loadings (forces, Moments, J_{app} and T_{app}) used in WCAP-13045 bound the plant-specific loadings. The licensee must confirm the limiting material fracture toughness values (J_{Ic}, T_{mat}, and J_{max}) used in WCAP-13045 and PWROG-17033-P-A bound the plant-specific fracture toughness values. If the screening loadings and material fracture toughness values in the WCAP-13045 and PWROG-17033-P-A reports bound plant-specific values, the licensee needs to discuss how the technical reports are bounding in the subsequent license renewal application. If the screening loadings or material fracture toughness values in the WCAP-13045 and PWROG-17033-P-A reports do not bound plant-specific values, the licensee needs to submit a

plant-specific crack stability analysis to demonstrate structural integrity of the RCP casing as part of the subsequent license renewal application.

As discussed in Section 5.4 of WCAP-18503-P, the plant-specific loadings for the reactor coolant pump casing are bounded by the screening loads implemented in the generic analysis performed in PWROG-17033-P-A. Furthermore, the plant specific fracture toughness values, per the guidance in NUREG/CR-4513 Revision 1 and NUREG/CR-4513 Revision 2, are shown to bound to the values implemented in WCAP-13045 and PWROG-17033-P-A. Therefore, the stability analysis performed in WCAP-13045, WCAP-15555, and PWROG-17033-P-A remains applicable for North Anna Units 1 and 2.

4. For the FCG analysis, the licensee must confirm that the transient cycles specified in the WCAP-13045 or PWROG-17033-P-A report bound the plant-specific transient cycles for the 80 years of operation. The licensee must confirm that the loading used in the FCG analysis in WCAP-13045 bound the plant-specific applied loadings, considering potential increase in applied loading caused by plant specific system operational changes, power uprate or piping modifications. If the FCG analysis inputs in WCAP-13045 bound the plant-specific conditions, the licensee must discuss how they are bounding in the subsequent license renewal application. If the FCG analysis inputs in WCAP-13045 do not bound the plant-specific conditions, the plant owner must provide a plant-specific analysis to demonstrate the FCG of the postulated flaw is within acceptable criteria as part of the subsequent license renewal application.

   The design transients implemented in the generic FCG analysis for the reactor coolant pump casing remain applicable for the subsequent period of extended operation, as indicated in WCAP-18503-P. Additionally, the design cycles used in the generic FCG analysis bound the projected transient cycles for 80 years of plant operation, as illustrated in Section 5.4 of WCAP-18503-P. An assessment for the FCG evaluation was performed in Section 4 of PWROG-17033-P-A for the pump casings. Based on the PWROG-17033-P-A assessment, it was determined that the latest FCG rate for stainless steel in water environment based on ASME Section XI as compared to the rates used in WCAP-13045 are comparable and there will be an insignificant impact on the crack growth analysis. The stresses used in the FCG analysis are generic and envelop the various pump designs. The stress intensity factors used in the FCG analysis are consistent with the current industry standards for similar FCG evaluations. Therefore, the generic FCG analysis performed in WCAP-13045, WCAP-15555 and PWROG-17033-P-A remains applicable for the subsequent period of extended operation at North Anna Units 1 and 2.

TLAA Disposition: 10 CFR 54.21(c)(1)(i)

Comparisons of RCS casing loads with the screening loads have been made. The stability of the flaws postulated in the RCS primary loop pump casings has been established by evaluating the necessary material properties against the saturated (fully aged) fracture toughness values. Thus, ASME Code Case N-481 is satisfied for the subsequent period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

4.7.7 CRACKING ASSOCIATED WITH WELD DEPOSITED CLADDING

TLAA Description:

Reactor vessel underclad cracking involves cracks in base metal forgings immediately beneath austenitic stainless steel cladding which are created as a result of the weld-deposited cladding process. Westinghouse performed an analysis of flaw growth associated with underclad cracking in 1971, concluding that RV integrity could be assured for the original plant license term. Underclad cracking only requires analysis if examinations have detected flaws (the analysis is not used to postulate flaws). Indications that could be representative of underclad cracking flaws have been detected under PWROG-16031-P, “Implementation of WCAP-16168-NP-A, Revision 3, for North Anna Units 1 and 2,” (Reference 4.8-80); therefore, the underclad cracking analysis is considered a TLAA, and the effects of fatigue on underclad cracking is evaluated through the subsequent period of extended operation.

Reactor vessel underclad cracking is discussed in UFSAR, Section 18.3.2.2, which references WCAP-15338-A, “A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants” (Reference 4.8-81).

TLAA Evaluation:

To extend this analysis to 60 years in support of initial license renewal, WCAP-15338-A provided an updated analysis of underclad cracking for Westinghouse units. WCAP-15338-A included fatigue crack growth analysis and ASME Code, Section XI allowable flaw size evaluations for typical Westinghouse vessels and found that the expected maximum flaw size predicted by the fatigue crack growth analysis is less than the ASME Code, Section XI allowable flaw size. WCAP-15338-A assumed 1.5 times the numbers of cyclic and transient loads assumed for the original 40-year life, and demonstrated that these effects were acceptable for a 60-year life. The NRC safety evaluation stated that any Westinghouse Owners Group plant may reference this report in a license renewal application to satisfy the requirements of 10 CFR 54.21(c)(1) regarding evaluation of TLAAs for RV components.

PWROG-17031-NP-A, “Update for Subsequent License Renewal: WCAP-15338-A, “A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants” (Reference 4.8-82), updated the 60-year fatigue crack growth analysis in WCAP-15338-A and confirmed the analysis remains appropriate for application to subsequent license renewal, up to 80 years of operation, subject to confirmation of the following TLAA Action Items noted in the included NRC Safety Evaluation.

- TLAA Action Item 1: Generic transient types and number of transient cycles used for the 80-year fatigue crack growth (FCG) calculation, as listed in the RCS transient table in the Letter from Ken Schrader, Pressurized Water Reactor Owners Group, to USNRC Document Control Desk, August 29, 2019, “Transmittal of the Response to Request for Additional Information, RAIs 1, 2 and 3 Associated with PWROG-17031-NP, Revision 1, Update for Subsequent License Renewal: WCAP-15338-A, 'A Review of Cracking Associated with Weld

Deposited Cladding in Operating PWR Plants” PA-MSC-1497," (Reference 4.8-83) bound the projected number of transient cycles for the subsequent period of extended operation as shown in Table 4.3.1-1. As discussed in WCAP-18503-P, the Excessive Feedwater Flow transient that appears in the Schrader letter is not a North Anna transient and does not appear in Table 4.3.1-1.

- TLAA Action Item 2: Limiting SA508, Class 2 or Class 3 RPV beltline forgings meet the 10 CFR 50.61 pressurized thermal shock (PTS) screening criterion of 270°F as noted in Section 4.2.3. Therefore the continued validity of the K_{1c} value of 200 ksi√in and thus the IWB-3610 allowable flaw depths would remain the same for the subsequent period of extended operation.
- TLAA Action Item 3: Units 1 and 2 have implemented Leak-Before Break (LBB) analyses for primary loop piping for the subsequent period of extended operation as noted in Section 4.7.3; therefore, the Large Break LOCA may be eliminated from consideration in the flaw evaluation.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

Reactor vessel underclad cracking associated with weld deposited cladding has been projected through the subsequent period of extended operation as noted in PWROG-17031-NP-A, and this TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

4.7.8 STEAM GENERATOR TUBE WEAR EVALUATION

TLAA Description:

As part of the Measurement Uncertainty Recapture (MUR) power uprate, the impact of changes to the secondary side fluid velocity and density were evaluated. The pre-MUR power uprate calculated tube wear is less than 8 mils corresponding to 40 years of operation. The expected tube wear over 60 years of operation is less than 12 mils.

Steam generator tube wear is discussed in UFSAR, Section 5.5.2.3.5.

TLAA Evaluation:

The tube wear evaluation, CN-SGDA-02-23, “The Effect of an Uprate to 2968 MWt NSSS Power for North Anna Units 1 and 2 on Steam Generator Tube Wear” (Reference 4.8-84) determined that less than 12 mils of wear is expected over 60 years of steam generator operation considering changes in secondary side fluid velocity and density related to MUR power uprate operating conditions. The replacement steam generator operating time at the end of 60 years of plant operation is 45 years, with 28 years in the uprated condition for Unit 1 and 30 years in the uprated condition for Unit 2, i.e., uprate in 2010 with operation to 2038 for Unit 1 and 2040 for Unit 2. Over 60 years of operation, the projected wear is still well below the tube wall margin.

For 80 years of operation, the replacement steam generator operating time at the end of 80 years of plant operation is 65 years, with 48 years in the uprated condition for Unit 1 and 50 years in the uprated condition for Unit 2, i.e., uprate in 2010 with operation to 2058 for Unit 1 and 2060 for Unit 2.

WCAP-18503-NP extrapolates the tube wear to 80 years of plant life and concludes that the calculated uprate tube wear at 60 years of operation will not result in unacceptably large rates of tube wear if extended to 80 years of operation.

Nonetheless, the steam generator tube wear will be managed by the *Steam Generators* program (B2.1.10) using the existing steam generator eddy current inspection consistent with NEI 97-06, “Steam Generator Program Guidelines.” (Reference 4.8-85)

TLAA Disposition: 10 CFR 54.21(c)(iii)

The wear evaluation for 80-year operation in WCAP-18503-NP demonstrates wear of the steam generator tubes will be acceptable through the subsequent period of extended operation. Nonetheless, the steam generator tube wear will be managed by the *Steam Generators* program (B2.1.10) and is dispositioned in accordance with 10 CFR 54.21(c)(iii).

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APPENDIX A

A0 INTRODUCTION

This appendix provides the information to be submitted in a Supplement to the Updated Final Safety Analysis Report (UFSAR) as required by 10 CFR 54.21(d) for the North Anna Power Station (NAPS), Units 1 and 2, Subsequent License Renewal Application (SLRA). Section 4.0 of the SLRA documents the evaluations of time-limited aging analyses (TLAA) for the subsequent period of extended operation. Appendix B of the SLRA provides descriptions of the programs and activities that manage the effects of aging for the subsequent period of extended operation. The information in Section 4.0 and Appendix B was used to prepare this appendix.

This appendix, which comprises the UFSAR supplement, includes the following sections:

- Section A1 contains summary descriptions of the aging management programs (AMPs) used to manage the effects of aging during the period of extended operation. The AMPs are either consistent with generally accepted industry methods as discussed in NUREG-2191 or require enhancements. Commitments for program additions and enhancements are identified in Section A4, Subsequent License Renewal Commitments. In addition, a discussion on quality assurance and operating experience related to aging management programs is provided in this section.
- Section A2 contains summary descriptions of AMPs used for management of TLAAs during the period of extended operation. The AMPs are either consistent with generally accepted industry methods as discussed in NUREG-2191 or require enhancements. Commitments for program additions and enhancements are identified in Section A4, Subsequent License Renewal Commitments.
- Section A3 contains evaluation summaries of TLAAs for the subsequent period of extended operation.
- Section A4 contains summary descriptions of subsequent license renewal commitments. Table A4.0-1, Subsequent License Renewal Commitments, includes the commitments for subsequent license renewal along with an associated schedule indicating when Dominion plans to complete each commitment.

Following issuance of the subsequent renewed operating licenses, information currently in the License Renewal section of the UFSAR, Chapter 18, will be replaced with the information in Appendix A described above. This is consistent with the requirements of 10 CFR 50.71(e). Upon inclusion in the UFSAR, future changes to the information in UFSAR Chapter 18 will be made under the provisions of 10 CFR 50.59.

A1 SUMMARY DESCRIPTIONS OF AGING MANAGEMENT PROGRAMS

The results of the integrated plant assessment and evaluation of time-limited aging analyses (TLAA) identified existing and new aging management programs necessary to provide reasonable assurance that components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis (CLB) for the subsequent period of extended operation. Sections A1 and A2 describe these programs and their implementation activities.

Quality Assurance for Aging Management Programs

The Quality Assurance (QA) Program is described in Topical Report DOM-QA-1, “Dominion Energy Nuclear Facility Quality Assurance Program Description,” which implements the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” The QA Program is consistent with the summary in Appendix A.2, “Quality Assurance for Aging Management Programs (Branch Technical Position IQMB-1)” of NUREG-2192. The QA Program provides the basis for the corrective actions, confirmation process, and administrative controls elements of aging management programs (AMPs). The scope of the existing QA Program is expanded to also include safety-related and nonsafety-related structures and components (SCs) subject to AMPs.

Consideration of Operating Experience in Aging Management Programs (AMPs)

Operating experience (OE) from plant-specific and industry sources is captured and systematically reviewed on an ongoing basis in accordance with the QA Program, which meets the requirements of 10 CFR 50, Appendix B, and the OE program, which meets the requirements of NUREG-0737, “Clarification of TMI Action Plan Requirements,” Item I.C.5, “Procedures for Feedback of Operating Experience to Plant Staff.”

The Dominion OE program interfaces with and relies on active participation in the INPO OE program, as endorsed by the NRC. In accordance with these programs, incoming OE items are screened to determine whether they may involve age-related degradation or aging management impacts. Research and development is 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 plant-specific and industry OE. Plant-specific OE associated with aging management and age-related degradation is reported to the industry in accordance with guidelines established in the Dominion OE program.

A1.1 ASME SECTION XI INSERVICE INSPECTIONS, SUBSECTIONS IWB, IWC, AND IWD

The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program is an existing condition monitoring program that manages cracking, loss of fracture toughness, and loss of material. The program consists of periodic volumetric, surface, and/or visual examinations, and leakage tests of ASME Class 1, 2, and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting for assessment, identification of signs of degradation, and establishment of corrective actions. The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program is implemented in accordance with 10 CFR 50.55a and ASME Code, Section XI. The ASME Code, Section XI, edition and addenda used will be consistent with the provisions of 10 CFR 50.55a during the subsequent period of extended operation.

Additional examinations associated with the ASME Code, Section XI, Inservice Inspection program are identified in the Augmented Inspection program, and are included in the ISI Schedule, for the following components:

- Pressurizer Safety Valve Inlet Lines
- Thermal Sleeves
- Reactor Vessel Core Barrel Holddown Spring
- Reactor Vessel Radial Supports
- Main Steam Postulated Break Locations
- Feedwater Postulated Break Locations
- Steam Generator Feedwater Nozzles
- Pressurizer Surge Line
- MRP-146 Thermal Fatigue
- MRP-227-A Reactor Vessel Internals Inspections

Inspections for three other aspects of the Augmented Inspection program are included in non-ISI programs. Inspections of reactor vessel incore detector thimble tubes are described in the *Flux Thimble Tube Inspection* program (A1.24). Inspections of the reactor vessel head are described in the *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program (A1.5). Inspections of the PWR vessel internals are described in the *PWR Vessel Internals* program (A1.7).

A1.2 WATER CHEMISTRY

The *Water Chemistry* program is an existing preventive program that manages cracking, loss of material, reduction of heat transfer, and wall thinning of components exposed to a reactor coolant, steam, treated borated water, and treated water environment. Chemistry programs are used to control water chemistry for impurities (e.g., chloride, fluoride, and sulfate) that accelerate corrosion. This program relies on monitoring and control of water chemistry to keep peak levels of various contaminants below the system-specific limits, based on Electric Power Research Institute (EPRI) guidelines EPRI 3002000505, Revision 7, “Pressurized Water Reactor Primary Water Chemistry Guidelines,” and EPRI 3002010645, Revision 8, “Pressurized Water Reactor Secondary Water Chemistry Guidelines.”

A1.3 REACTOR HEAD CLOSURE STUD BOLTING

The *Reactor Head Closure Stud Bolting* program is an existing condition monitoring program that manages cracking and loss of material for the reactor head closure stud assembly (which includes the closure studs, nuts, and washers) and for the threads in the reactor vessel flange.

The Reactor Head Closure Stud Bolting program is implemented through procedures based on the examination requirements specified in the ASME Code, Section XI, Subsection IWB, Table IWB-2500-1, and preventive measures to mitigate cracking. The program relies on preventive measures to address reactor head closure stud bolting degradation consistent with those identified in NRC Regulatory Guide 1.65, Revision 1, “Material and Inspection for Reactor Vessel Closure Studs.”

A1.4 BORIC ACID CORROSION

The *Boric Acid Corrosion* program is an existing condition monitoring program that manages loss of material due to leaking borated water on structures and components (including electrical equipment/junction boxes). This program relies, in part, on the response to Generic Letter 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 to reactor coolant pressure boundary components. The program also includes inspections, evaluations, and corrective actions for components subject to aging management review that may be adversely affected by some form of borated water leakage.

This program includes provisions to initiate evaluations and assessments when leakage is discovered by activities not associated with the program. This program follows the guidance described in Section 7 of WCAP-15988-NP, Revision 2, “Generic Guidance for an Effective Boric Acid Inspection Program for Pressurized Water Reactors.”

A1.5 CRACKING OF NICKEL-ALLOY COMPONENTS AND LOSS OF MATERIAL DUE TO BORIC ACID-INDUCED CORROSION IN REACTOR COOLANT PRESSURE BOUNDARY COMPONENTS

The *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program is an existing condition monitoring program that addresses operating experience of degradation due to primary water stress corrosion cracking (PWSCC) for components or welds constructed from Alloy 600/82/182 and exposed to pressurized water reactor (PWR) primary coolant at elevated temperatures.

The scope of the program includes the following groups of components and materials:

(a) Nickel alloy components and welds identified in “Materials Reliability Program: Generic Guidance for Alloy 600 Management,” (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.

The Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components program is used in conjunction with the *Water Chemistry* program (A1.2).

For nickel-alloy components and welds identified in EPRI MRP-126 and addressed by the regulatory requirements of 10 CFR 50.55a, examinations are conducted in accordance with 10 CFR 50.55a and EPRI MRP-126.

A1.6 THERMAL AGING EMBRITTLEMENT OF CAST AUSTENITIC STAINLESS STEEL (CASS)

The *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* program is an existing condition monitoring program that manages loss of fracture toughness of cast austenitic stainless steel reactor coolant pressure boundary components with service conditions above 250 °C (Celsius) [482 °F (Fahrenheit)].

The program determines the susceptibility of CASS piping and piping components in reactor coolant pressure boundaries with regard to thermal aging embrittlement based on the casting method, molybdenum content, and ferrite percentage.

Aging management of potentially susceptible piping and piping components is accomplished through a component-specific flaw tolerance evaluation in accordance with the ASME Code, Section XI and Code Case N-838 that demonstrated flaw crack growth remains acceptable for the subsequent period of extended operation.

A1.7 PWR VESSEL INTERNALS

The *PWR Vessel Internals* program is an existing condition monitoring program that manages change in dimensions due to void swelling, cracking, loss of fracture toughness, loss of material, and loss of preload for the reactor vessel internals (RVI). The aging effect of cracking includes stress corrosion cracking (SCC), primary water stress corrosion cracking (PWSCC), irradiation-assisted stress corrosion cracking (IASCC), and cracking due to fatigue/cyclic loading. Degradation due to loss of material can be induced by wear, and loss of fracture toughness is the result of thermal aging and neutron irradiation embrittlement. Potential causes for the aging effect of changes in dimensions are void swelling or distortion, and loss of preload can result from thermal and irradiation-enhanced stress relaxation or creep.

The PWR Vessel Internals program relies on implementation of the inspection and evaluation guidelines in Electric Power Research Institute (EPRI) Technical Report 3002017168, “Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines, (MRP-227, Revision 1-A)”, and EPRI Technical Report 3002010399, “Materials Reliability Program: Inspection Standard for Pressurized Water Reactor Internals - 2018 Update (MRP-228, Rev. 3),” to manage the aging effects on the reactor vessel internal components, as supplemented by a gap analysis. The guidelines listed in MRP-227, Revision 1-A, provide an appropriate aging management methodology for the RVI components up to a 60-year operating period. The EPRI basis document that provides functionality analyses for the aging management methodology is Technical Report 3002007955, “Materials Reliability Program: Functionality Analysis for Westinghouse and Combustion Engineering Representative PWR Internals (MRP-230, Revision 2, Supplement 1)”. The failure modes, effects, and criticality analysis from EPRI Technical Report 3002013220, “Materials Reliability Program: Screening, Categorization, and Ranking of Reactor Internals Components for Westinghouse and Combustion Engineering PWR Designs (MRP-191, Revision 2),” provides the basis for grouping the reactor internals components into inspection categories by assessing aging effects and relevant time-dependent aging parameters.

For the 80-year operating period, the gap analysis integrates the interim guidance from MRP 2018-022, “Transmittal of MRP-191 Screening, Ranking, and Categorization Results and Interim Guidance in Support of Subsequent License Renewal at U.S. PWR Plants,” for additional inspections not listed in MRP-227, Revision 1-A. The gap analysis further integrates guidance for inspections of the following components:

a. CRGT assembly continuous section sheath and C-tube expansion component inspections in accordance with WCAP-17451-P, Revision 2,

b. Middle axial weld (MAW) and lower axial weld (LAW) primary component one-time inspections in accordance with MRP 2019-009.

A1.8 FLOW-ACCELERATED CORROSION

The *Flow-Accelerated Corrosion* program is an existing condition monitoring program that manages wall thinning caused by flow-accelerated corrosion, as well as wall thinning due to erosion mechanisms. Erosion monitoring is performed for the internal surfaces of metallic piping and components to manage the aging effect of wall thinning due to cavitation, flashing, liquid droplet impingement, and solid particle erosion.

The program is consistent with the Virginia Electric and Power Company response to NRC Generic Letter 89-08, “Erosion/Corrosion-Induced Pipe Wall Thinning,” and relies on implementation of EPRI guidelines listed in NSAC-202L, Revision 4, “Recommendations for an Effective Flow Accelerated Corrosion Program.” The erosion activity implements the recommendations of EPRI 3002005530, “Recommendations for an Effective Program Against Erosive Attack.”

The program includes (a) identifying flow accelerated corrosion (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 operating experience, selecting a sample of components for inspection; (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 modeling.

The program tracks and predicts occurrences of wall thinning due to FAC using CHECWORKS-SFA™ software. The CHECWORKS-SFA™ model is evaluated and updated as required to reflect any significant changes in plant operating parameters such as power uprates. Wall thinning information available from the CHECWORKS-SFA™ software is one of the tools used to determine the scope and required schedule for inspections of FAC-susceptible components.

In addition to planned inspections performed for the Flow-Accelerated Corrosion program, opportunistic visual inspections of internal surfaces are conducted during routine maintenance activities to identify degradation.

A1.9 BOLTING INTEGRITY

The *Bolting Integrity* program is an existing condition monitoring program that manages aging by performing periodic visual inspections for indications of cracking, loss of material due to general, pitting, and crevice corrosion, microbiologically-influenced corrosion, loss of preload, and wear as evidenced by leakage for safety-related and nonsafety-related closure bolting on pressure-retaining components within the scope of subsequent license renewal.

The program relies on recommendations as delineated in NUREG-1339, “Resolution of Generic Safety Issue 29: Bolting Degradation of Failure in Nuclear Power Plants,” and EPRI report NP-5769, “Degradation and Failure of Bolting in Nuclear Power Plants,” with exceptions noted in NUREG-1339 for safety related piping. The program also relies upon industry recommendations as delineated in EPRI Report 1015336, “Nuclear Maintenance Application Center: Bolted Joint Fundamentals,” and EPRI Report 1015337, “Nuclear Maintenance Application Center: Assembling Gasketed Flanged Bolted Joints.”

The program includes inspections or testing for closure bolting for which leakage is difficult to detect, including applicable submerged bolting, and for piping systems that contain compressed air, hydrogen, nitrogen, oxygen, freon, halon and carbon dioxide. The absence of high-strength bolting precludes the need for sampling-based volumetric examinations for high-strength bolting. The program includes preventive measures to preclude or minimize loss of preload and cracking.

The ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program includes inspections of closure bolting within the scope of ASME Code, Section XI, and supplements this Bolting Integrity program. The following aging management programs manage aging effects associated with safety-related and nonsafety-related structural bolting:

- ASME Section XI, Subsection IWE program (Section A1.29)
- ASME Section XI, Subsection IWF program (Section A1.31)
- Structures Monitoring program (Section A1.34)
- Inspection of Water-Control Structures Associated with Nuclear Power Plants program (Section A1.35)
- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program (Section A1.13)

A1.10 STEAM GENERATORS

The *Steam Generators* program is an existing condition monitoring program that manages the aging effects of cracking, loss of material (e.g., wall thinning), and reduction of heat transfer for the steam generators. The scope of the program includes primary-side components (e.g., U-tubes [tubes], plugs, channel head divider plate, channel head, tubesheet, etc), and secondary-side components that are contained within the steam generator. The program uses volumetric inspections for the tubes, and visual inspections for the other primary-side and secondary-side components. The visual inspections of 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.

Provisions in the Steam Generators program address reporting criteria, inspection scope and frequency, assessments, plugging criteria, and water chemistry monitoring to maintain consistency with established requirements. NEI 97-06, Revision 3, “Steam Generator Program Guidelines,” and associated EPRI guidelines, provide a generic industry program to implement Technical Specifications.

As stated in the steam generator DA, tubing and primary-side inspections are typically performed every third refueling outage for each steam generator, thus satisfying the guidance for visual inspections to be performed at least every 72 effective full power months or every third refueling outage, whichever results in more frequent inspections. The DA includes a review of applicable industry operating experience (OE) and plant-specific OE which has occurred since the previous DA was performed. The DA review determines the existence of any unaddressed mechanism that could adversely affect steam generator primary-side or secondary-side integrity, as well as the effects of any chemistry excursions or transients that could affect existing degradation mechanisms.

The Steam Generators program includes preventive measures to mitigate aging related to corrosion phenomena, and through foreign material exclusion as a means to inhibit tube degradation due to wear. Identification of deposits on the secondary side of the steam generator, and the subsequent removal of sludge deposits help avoid tube degradation.

The Technical Specifications require condition monitoring and operational assessments to be performed to ensure tube integrity will be maintained until the next inspection. The operational assessments are performed after steam generator inspections have been completed to verify structural and leakage integrity.

A1.11 OPEN-CYCLE COOLING WATER SYSTEM

The *Open Cycle Cooling Water System* program is an existing preventive, mitigative, condition monitoring, and performance monitoring program that manages cracking, flow blockage, loss of material, and reduction of heat transfer, for the piping, piping components, and heat exchangers identified in the responses to NRC Generic Letter (GL) 89-13, “Service Water System Problems Affecting Safety-Related Equipment.” The program is comprised of the aging management aspects of the Virginia Electric and Power Company response to NRC GL 89-13 and includes: (a) surveillance and control to reduce the incidence of flow blockage problems as a result of biofouling, (b) tests to verify heat transfer of safety-related heat exchangers, (c) routine inspection and maintenance so that loss of material, corrosion, erosion, cracking, fouling, and biofouling cannot degrade the performance of systems serviced by the open-cycle cooling water system. This program includes enhancements to the guidance in NRC GL 89-13 that address operating experience (OE) to provide reasonable assurance that aging effects are adequately managed.

System and component testing, visual inspections, nondestructive examination (i.e., ultrasonic testing and eddy current testing), and chemical injection are conducted to ensure that identified aging effects are managed such that system and component intended functions and integrity are maintained. Periodic heat transfer testing, visual inspection and cleaning of safety-related heat exchangers with a heat transfer intended function is performed in accordance with the Virginia Electric and Power Company commitments to GL 89-13 to verify heat transfer capabilities.

The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (A1.28) will manage the aging effects of internal surface coatings.

A1.12 CLOSED TREATED WATER SYSTEMS

The *Closed Treated Water Systems* program is an existing program that manages cracking, loss of material, and reduction of heat transfer for components exposed to a closed treated water environment.

This is a mitigation program that also includes a condition monitoring program to verify the effectiveness of the mitigation activities. The program consists of: (a) water treatment, including the use of corrosion inhibitors, to modify the chemical composition of the water such that the effects of corrosion 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. The program uses as applicable, EPRI Report 3002000590, “Closed Cooling Water Chemistry Guideline.” Microbiological testing is performed as a diagnostic chemistry parameter for selected system water treatments.

A1.13 INSPECTION OF OVERHEAD HEAVY LOAD AND LIGHT LOAD (RELATED TO REFUELING) HANDLING SYSTEMS

The *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program is an existing condition monitoring program that manages cracking, loss of material due to corrosion and wear, and loss of preload on bolted connections for cranes and hoists within the scope of subsequent license renewal. The program includes periodic visual inspections to detect degradation of bridge, rail, and trolley structural components and bolted connections. This program relies on the guidance in NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants,” ASME B30.2, “Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist),” and other appropriate standards in the ASME/ANSI B30 series to manage aging.

A1.14 COMPRESSED AIR MONITORING

The *Compressed Air Monitoring* program is an existing preventive and condition monitoring program that manages loss of material. The *Compressed Air Monitoring* program includes monitoring of air moisture content and contaminants such that specified limits are maintained, and performance of opportunistic inspections of components for indications of loss of material.

This program is consistent with the North Anna response to NRC GL 88-14, “Instrument Air Supply Problems;” and INPO SOER 88-01, “Instrument Air System Failures,” The program relies on guidance and standards provided in EPRI TR 108147, “Compressor and Instrument Air System Maintenance Guide: Revision to NP-7079,” and ANSI/ISA-S7.3-1975, “Quality Standard for Instrument Air,” for testing and monitoring air quality and moisture. The *Compressed Air Monitoring* program activities implement the moisture content and contaminant criteria of ANSI/ISA-S7.3-1975 (incorporated into ISA-S7.0.01-1996).

Program activities include air quality checks at various locations to ensure that dew point, particulates, and hydrocarbons are maintained within the specified limits. Opportunistic inspections of the internal surfaces of select compressed air system components for loss of material are performed.

A1.15 FIRE PROTECTION

The *Fire Protection* program is an existing condition and performance monitoring program that requires periodic visual inspections of fire barrier components and functional testing of fire doors and halon and low pressure carbon dioxide fire suppression systems. The program manages:

- Loss of material for fire-rated doors, fire damper assemblies, the halon systems, RCP oil collection system, steel seismic gap covers and the low-pressure carbon dioxide systems
- Loss of material or cracking for concrete structures, including fire barrier walls, ceilings, and floors
- Hardening, shrinkage, and loss of strength for elastomer fire barrier penetration seals and seismic gap elastomers
- Loss of material and cracking for non-elastomer fire barrier penetration seals, fire stops, containment radiant energy shields, fire wraps, and coatings.

A1.16 FIRE WATER SYSTEM

The *Fire Water System* program is an existing condition monitoring program that manages cracking, flow blockage, and, loss of material for in-scope water-based fire protection systems. This program manages cracking, flow blockage, and, loss of material by conducting periodic visual inspections, flow testing, and flushes performed in accordance with the NFPA 25, 2011 Edition. Testing or replacement of sprinklers that have been in place for 50 years is performed in accordance with NFPA 25, 2011 Edition.

With exception of two locations that will be reconfigured to allow drainage, portions of the water-based fire protection system that have been wetted but are normally dry have been confirmed to drain and are not subjected to augmented testing and inspections.

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 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 to obstruct piping or sprinklers is detected, the material is removed, and the source is detected and 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 that ensure an adequate examination.

A1.17 OUTDOOR AND LARGE ATMOSPHERIC METALLIC STORAGE TANKS

The *Outdoor and Large Atmospheric Metallic Storage Tanks* program is an existing condition monitoring program that manages the effects of cracking and loss of material on the outside and inside surfaces of aboveground metallic tanks constructed on concrete or soil. This program is a condition monitoring program that manages aging effects associated with outdoor tanks with internal pressures approximating atmospheric pressure including the refueling water storage tanks (RWSTs), refueling water chemical addition tanks (CATs), casing cooling tanks (CCTs), and emergency condensate storage tanks (ECSTs). The program includes preventive measures to mitigate corrosion by protecting the external surfaces of steel components consistent with standard industry practices. The RWSTs and CCTs are insulated and rest on a concrete foundation covered with an oil sand cushion. Caulking is used at the concrete-component interface of the RWSTs and CCTs. The CATs are skirt supported and insulated. The ECSTs are internally coated and protected by concrete missile barriers.

The program manages loss of material on tank internal bare metal surfaces by conducting visual inspections. Inspections of RWST and CCT caulking/sealants are supplemented with physical manipulation. Surface exams of external tank surfaces are conducted to detect cracking on the stainless-steel tanks. Thickness measurements of the tank's bottoms are conducted to ensure that significant degradation is not occurring. The external surfaces of insulated tanks are periodically sampling-based inspected. Inspections not conducted in accordance with ASME Code, Section XI requirements are conducted in accordance with plant-specific procedures that include inspection parameters such as lighting, distance, offset, and surface conditions.

The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (A1.28) will manage the internally coated surfaces of the ECSTs. Internal surfaces of the RWSTs, CATs, and CCTs will be managed by the *One-Time Inspection* program (A1.20). Tank reinforced concrete foundations and the reinforced concrete missile barrier of the ECSTs will be managed by the *Structures Monitoring* program (A1.34).

A1.18 FUEL OIL CHEMISTRY

The *Fuel Oil Chemistry* program is an existing mitigative and condition monitoring and preventive program that manages cracking or blistering, flow blockage, hardening or loss of strength, loss of material, and reduction of heat transfer from tanks, piping, and components in a fuel oil environment. The program includes activities which provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of subsequent license renewal.

This program relies on a combination of surveillance and maintenance procedures. Fuel oil quality is maintained by monitoring and controlling fuel oil contamination in accordance with Technical Specifications, the Technical Requirements Manual, and ASTM standards such as ASTM D 0975, D 1796, D 2276, D 2709, D 6217, and D 4057.

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 oil before its introduction into the storage tanks. Where internal cleaning and inspection are not physically possible, bottom thickness measurements of inaccessible tanks will be performed in lieu of cleaning and internal inspection.

A1.19 REACTOR VESSEL MATERIAL SURVEILLANCE

The *Reactor Vessel Material Surveillance* program is an existing condition monitoring program that manages reduction of fracture toughness of the ferritic reactor vessel beltline materials, in accordance with the version of ASTM E185 available and used during fabrication of the reactor vessels. The program provides sufficient material to monitor reduction of fracture toughness due to neutron irradiation embrittlement until the end of the subsequent period of extended operation, and determine the need for operating restrictions on the irradiation temperature (i.e., cold leg operating temperature), neutron spectrum, and neutron fluence.

The *Reactor Vessel Material Surveillance* program complies with ASTM E185-73 for the design and number of required capsules, and ASTM E185-82 for the withdrawal schedules and test methods, as incorporated by reference in 10 CFR 50, Appendix H. The withdrawal schedule in Table 1 of ASTM E185-82 is based on plant operation during the original 40 year initial license term. Standby capsules have been incorporated into the program. The Reactor Vessel Material Surveillance program includes removal and testing of at least one capsule, with a neutron fluence of the capsule between one and two times the projected peak vessel neutron fluence at the end of the subsequent period of extended operation. If a capsule meeting this criterion has not been tested previously, then at least one capsule will be removed and tested during the subsequent period of extended operation (or earlier) to meet this criterion.

Data from the *Reactor Vessel Material Surveillance* program is used to monitor neutron irradiation embrittlement of the reactor vessel, and is provided as input to the neutron embrittlement time limited aging analyses described in Section A3.2, Reactor Vessel Neutron Embrittlement Analysis.

In accordance with 10 CFR 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 subsequent period of extended operation, are submitted for approval by the Nuclear Regulatory Commission (NRC) prior to implementation, in accordance with 10 CFR 50, Appendix H, Paragraph III.B.3. Standby capsules placed in storage (e.g., removed from the reactor vessel) are maintained for possible future insertion. If one or more capsules will not be maintained in such a way as to permit future insertion, then the NRC shall be notified of the change.

The Reactor Vessel Material Surveillance program is also used in conjunction with the *Neutron Fluence Monitoring* program (A2.2) which monitors neutron fluence for reactor vessel components and reactor vessel internal components.

A1.20 ONE-TIME INSPECTION

The *One-Time Inspection* program is a new condition monitoring program that will manage cracking, loss of material, and reduction of heat transfer of components containing reactor coolant, treated borated water, secondary water, fuel oil, air, condensation, or lubricating oil environments.

The program 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 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 program include: (a) determination of the sample size of components to be inspected based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience, (b) identification of the inspection locations in the system or component based on the potential for the aging effect to occur, (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (d) an evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the subsequent period of extended operation.

Periodic inspections instead of this program are used for structures or components with known age-related degradation mechanisms or when the environment in the subsequent period of extended operation 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.

Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

A1.21 SELECTIVE LEACHING

The *Selective Leaching* program is a new condition monitoring program that will manage loss of material of the susceptible materials located in a potentially aggressive environment. The materials of construction for these components may include gray cast iron, ductile iron, and copper alloys (greater than 15% zinc).

One-time inspections for components exposed to closed-cycle cooling water or treated water environments will be conducted when plant-specific operating experience has not revealed selective leaching in these environments. Opportunistic and periodic inspections will be conducted for raw water, waste water, soil, and groundwater environments, and for closed-cycle cooling water or treated water environments when plant specific operating experience has revealed selective leaching in these environments. Visual inspections coupled with mechanical examination techniques such as chipping, or scraping will be conducted. Periodic destructive examinations of components for physical properties (i.e., degree of de-alloying, through-wall thickness, and chemical composition) will be conducted for components exposed to raw water, waste water, soil, and groundwater environments or for closed-cycle cooling water or treated water environments when plant specific operating experience has revealed selective leaching in these 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 subsequent period of extended operation. Inspections are performed by personnel qualified in accordance with 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 inspection procedures will include requirements for items such as lighting, distance, offset, and surface conditions. When the acceptance criteria are not met such that it is determined that the affected component be replaced prior to the end of the subsequent period of extended operation, additional inspections will be performed.

Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

A1.22 ASME CODE CLASS 1 SMALL-BORE PIPING

The *ASME Code Class 1 Small-Bore Piping* program is a new condition monitoring program that will manage cracking in ASME Code Class 1 small-bore piping that is defined as greater than or equal to 1 inch nominal pipe size (NPS) and less than 4 inches NPS. This program will utilize volumetric or destructive examinations to augment examinations performed by the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program. One-time inspections and periodic inspections will determine the presence of cracking for locations within the scope of the *ASME Code Class 1 Small-Bore Piping* program including full penetration (butt) and partial penetration (socket) welds.

Age-related cracking has been experienced in both Units 1 and 2 reactor coolant system cold leg drain butt-welded piping. Although corrective actions have been taken to address the cause and risk of cracking, the cause of cracking has not been fully mitigated. Therefore, Category C criteria is required as described in NUREG-2191, Table XI.M35-1 for performing periodic volumetric or destructive inspections of susceptible butt welds for both units.

With the exception of the reactor coolant pump (RCP) seal injection-thermal barrier (SI-TB) nozzle welds, age-related cracking has not been identified in Class 1 small bore socket welded piping, Category A criteria is required for examination of Class 1 small bore socket weld locations for both units that are susceptible to cracking. Should evidence of cracking be revealed by a one-time inspection, a periodic inspection consistent with Category C criteria is required.

Based on the unique design of the original Westinghouse factory welds used for the RCP SI-TB joint, these factory welds are addressed as a unique subset. Inspection samples will be selected consistent with NUREG-2191, Section XI.M35, Table XI.M35-1, Category C for this subset of welds due to the cracking that occurred in 1994 and 2020. Upon replacement of all Class 1 RCP thermal barrier nozzle welds with an improved design, the cause of the cracking will be considered mitigated and inspection samples will be selected consistent with NUREG-2191, Section XI.M35, Table XI.M35-1, Category B for this subset of welds.

Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.

A1.23 EXTERNAL SURFACES MONITORING OF MECHANICAL COMPONENTS

The *External Surfaces Monitoring of Mechanical Components* program is an existing condition monitoring program that manages the following aging effects:

- loss of material, cracking, and reduction of heat transfer of metallic components;
- hardening or loss of strength, loss of material, and cracking or blistering of polymeric components;
- hardening or loss of strength, and loss of material of elastomeric components;
- loss of material, cracking, and loss of preload of HVAC closure bolting; and
- reduced thermal insulation resistance

Periodic visual inspections, not to exceed a refueling outage interval, of metallic, polymeric, and insulation jacketing (insulation when not jacketed) are conducted. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength is used to augment the visual inspections conducted under this program.

Surface examinations or ASME Code, Section XI, visual examinations (VT-1) are conducted to detect cracking of stainless steel, nickel-alloy, and copper alloy (>15% Zn) components.

A sample of outdoor component surfaces that are insulated and a sample of indoor insulated components exposed to condensation (due to the in-scope component being operated below the dew point), are periodically inspected every 10 years during the subsequent period of extended operation.

Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset, and surface conditions.

Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the subsequent period of extended operation. Qualitative acceptance criteria are clear enough to reasonably assure a singular decision is derived based on observed conditions.

The external surfaces of components that are buried or in underground environments are inspected by the *Buried and Underground Piping and Tanks* program (A1.27). The external surfaces of outdoor tanks and indoor large volume metallic storage tanks (capacity >100,000 gallons) are inspected by the *Outdoor and Large Atmospheric Metallic Storage Tanks* program (A1.17). Loss of material due to boric acid corrosion is managed by the *Boric Acid Corrosion* program (A1.4).

A1.24 FLUX THIMBLE TUBE INSPECTION

The *Flux Thimble Tube Inspection* program is an existing condition monitoring program that manages loss of material due to wear by inspecting for the thinning of flux thimble tube walls. Flux thimble tubes provide a path for the in-core neutron flux monitoring system detectors and form part of the reactor coolant system pressure boundary. Flux thimble tubes are subject to loss of material at certain locations in the reactor vessel where flow-induced fretting causes wear at discontinuities in the path from the reactor vessel instrument nozzle to the fuel assembly instrument guide tube. Periodic eddy current examinations are performed to confirm the integrity of the flux thimble tubes, and are consistent with the recommendations of Inspection and Enforcement Bulletin 88-09 (IEB 88-09), “Thimble Tube Thinning in Westinghouse Reactors.”

A1.25 INSPECTION OF INTERNAL SURFACES IN MISCELLANEOUS PIPING AND DUCTING COMPONENTS

The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program is an existing condition monitoring program that manages the following aging effects:

- hardening or loss of strength, loss of material, cracking or blistering, and flow blockage of polymeric components
- loss of material, cracking, reduction of heat transfer, and flow blockage of metallic components

This program consists of visual inspections of all accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components, and other components. Applicable environments include closed–cycle cooling water, raw water, treated water, diesel exhaust, air – dry, condensation, fuel oil, lubricating oil, and waste water.

Surface examinations or ASME Code, Section XI, visual examinations (VT-1) are conducted to detect cracking of stainless steel and copper alloy (>15% Zn) components. Aging effects associated with items within the scope of the Open-Cycle Cooling Water System program (A1.11), *Closed Treated Water Systems* program (A1.12), and *Fire Water System* program (A1.16) are not managed by this program.

The internal inspections are performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. At a minimum, in each 10-year period during the subsequent period of extended operation, 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 focus on the bounding or lead components most susceptible to aging because of time in service and severity of operating conditions. Opportunistic inspections continue in each period, even if the minimum number of inspections has been conducted. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength is used to augment the visual examinations conducted under this program.

Inspections not conducted in accordance with ASME Code, Section XI requirements are conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset and surface conditions. Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the subsequent period of extended operation. Qualitative acceptance criteria are clear enough to reasonably ensure a singular decision is derived based on observed conditions.

A1.26 LUBRICATING OIL ANALYSIS

The *Lubricating Oil Analysis* program is an existing preventive program that ensures that loss of material and reduction of heat transfer is not occurring by maintaining the quality of the lubricating oil or hydraulic oil. The program ensures that contaminants (primarily water and particulates) are within acceptable limits. Testing activities include sampling and analysis of lubricating oil for detrimental contaminants. Oil testing that indicates the presence of water or particulates results in the initiation of corrective action that may include evaluating for inleakage.

A1.27 BURIED AND UNDERGROUND PIPING AND TANKS

The *Buried and Underground Piping and Tanks* program is an existing condition monitoring program that manages blistering, cracking, and loss of material on external surfaces of components in soil, concrete, or underground environments within the scope of subsequent license renewal through preventive and mitigative actions. The program addresses piping and tanks composed of stainless steel, carbon steel, cast iron, ductile iron, copper alloy, and fiberglass.

Depending on the material, preventive and mitigative techniques include external coatings, cathodic protection (CP), and the quality of backfill. Direct visual inspection quantities for buried components are planned using procedural categorization criteria. Transitioning to a higher number of inspections than originally planned is based on the effectiveness of the preventive and mitigative actions. Also, depending on the material, inspection activities include annual surveys of CP, nondestructive evaluation of pipe or tank wall thicknesses, and visual inspections of the pipe from the exterior. For steel components, where the acceptance criteria for the effectiveness of the cathodic protection is other than -850 mV instant off, loss of material rates are measured.

Soil sampling and testing is performed during each excavation and a station-wide soil survey based on initial baseline data is also performed once in each 10-year period to confirm the soil corrosivity level near components within the scope of subsequent license renewal for the installed material types.

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 subsequent period of extended operation an increase in the sample size is conducted.

As an alternative to performing visual inspections of the buried fire protection system components, monitoring the activity of the jockey pump is performed by the *Fire Water System* program (A1.16).

A1.28 INTERNAL COATINGS/LININGS FOR IN-SCOPE PIPING, PIPING COMPONENTS, HEAT EXCHANGERS, AND TANKS

The *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program is an existing condition monitoring program that manages loss of coating integrity of the in-scope components, exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water, lubricating oil, fuel oil, and air-dry environments, that can lead to loss of base material or downstream effects such as reduction in flow, reduction in pressure or reduction of heat transfer when coatings/linings become debris. The program manages loss of material or cracking for cementitious coatings/linings.

Periodic visual inspections are conducted of each coating/lining material and environment combinations applied to the internal surfaces of in-scope piping and components where loss of coating or lining integrity could impact the components or downstream component's intended function(s).

For tanks, heat exchangers and piping, all accessible surfaces are inspected. The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings are conducted in accordance with ASTM International Standards endorsed in RG 1.54, Revision 3, “Service Level I, II and III Protective Coatings Applied to Nuclear Power Plants,” including guidance from the staff associated with a particular standard. For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces. Peeling and delamination is not acceptable. Blisters are evaluated by a coatings specialist. Blisters are limited to a few intact small blisters that are completely surrounded by sound material and with the size and frequency not increasing between inspections. Minor cracks in cementitious coatings are acceptable provided there is no evidence of debonding. Other degraded conditions are evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, the coating can be removed, or physical testing is performed, where physically possible (i.e., sufficient room to conduct testing), in conjunction with repair or replacement of the coating/lining.

A1.29 ASME SECTION XI, SUBSECTION IWE

The *ASME Section XI, Subsection IWE* program is an existing condition monitoring program that manages cracking, loss of leak tightness, loss of material, loss of preload, and loss of sealing. This program is in accordance with ASME Code, Section XI, Subsection IWE, consistent with 10 CFR 50.55a, “Codes and standards,” with supplemental recommendations. The *ASME Section XI, Subsection IWE* program includes periodic visual, surface, and volumetric examinations, where applicable, of the metallic pressure-retaining components of the concrete Containment for signs of degradation, damage, irregularities including discernible liner plate bulges, and for coated areas, distress that might be indicative of degradation of the underlying metal shell or liner, and corrective actions. Acceptability of inaccessible areas of the concrete containment steel liner is evaluated when conditions found in accessible areas, indicate the presence of, or could result in, flaws or degradation in inaccessible areas.

This program also includes surface examination for the detection of cracking of structural bolting. In addition, the program includes supplemental surface or enhanced examinations to detect cracking for specific pressure-retaining components. A one-time volumetric examination of metal liner surfaces that are inaccessible from one side will be performed if triggered by plant-specific operating experience. Sampling locations will be those susceptible to loss of thickness due to corrosion of the containment liner that is inaccessible from one side. Inspection results will be compared with prior recorded results in acceptance of components for continued service.

In conformance with 10 CFR 50.55a(g)(4)(ii), the containment inservice inspection program will be updated during each successive 120-month inspection interval to comply with the requirements of the latest edition and addenda of the ASME Code specified 12 months before the start of the inspection interval

A1.30 ASME SECTION XI, SUBSECTION IWL

The *ASME Section XI, Subsection IWL* program is an existing condition monitoring program that manages the following aging effects for containment concrete:

- Cracking
- Cracking and distortion
- Cracking; loss of bond; and loss of material (spalling, scaling)
- Cracking; loss of material
- Increase in porosity and permeability; cracking; loss of material (spalling, scaling)
- Increase in porosity and permeability; loss of strength
- Loss of material (spalling, scaling) and cracking

The design of the reinforced concrete containment does not utilize prestressing tendons. This program consists of periodic visual inspection of concrete surfaces for reinforced concrete containments for signs of degradation, assessment of damage, and corrective actions. The Subsection IWL requirements are supplemented to include quantitative acceptance criteria for concrete surfaces based on the "Evaluation Criteria" provided in Chapter 5 of ACI 349.3R.

A1.31 ASME SECTION XI, SUBSECTION IWF

The *ASME Section XI, Subsection IWF* program is an existing condition monitoring program that manages cracking, loss of mechanical function, loss of material, and loss of preload for supports of Class 1, 2, and 3 components. There are no Class MC supports. This program consists of periodic visual examination of piping and component supports for signs of degradation, evaluation, and corrective actions. This program recommends additional inspections beyond the inspections required by the 10 CFR Part 50.55a ASME Section XI, Subsection IWF program. This includes a one-time inspection within five years prior to entering the subsequent period of extended operation 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. For high-strength bolting with an actual yield strength equal to or greater than 150 ksi in sizes greater than one inch nominal diameter, volumetric examination comparable to that of ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 are 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.

A1.32 10 CFR PART 50, APPENDIX J

The *10 CFR Part 50, Appendix J* program is an existing performance monitoring program that manages cracking, loss of leak tightness, loss of material, loss of preload and loss of sealing. Leakage rates through the Containment pressure boundary are monitored, including the Containment liner, associated welds, penetrations, isolation valves, fittings, and other access openings to detect degradation of the Containment pressure boundary. Corrective actions are taken if leakage rates exceed acceptance criteria. Leakage rate testing is performed in accordance with the regulations and guidance provided in 10 CFR Part 50, Appendix J, Option B; Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program;" NEI 94-01, Revision 3-A, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J," and Section 4.1 "Limitations and Conditions for NEI TR 94-01, Revision 2" of the NRC Safety Evaluation Report in NEI 94-01, Revision 2-A; and subject to the requirements of 10 CFR Part 54.

A1.33 MASONRY WALLS

The *Masonry Walls* program is an existing condition monitoring program that is implemented as part of the *Structures Monitoring* program (A1.34) and manages cracking, loss of material, and loss of material (spalling and scaling) that could impact the intended function of the masonry walls. The *Masonry Walls* program consists of inspections, consistent with Inspection and Enforcement Bulletin 80-11, and plant-specific monitoring, proposed by Information Notice 87-67, 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.

A1.34 STRUCTURES MONITORING

The *Structures Monitoring* program is an existing condition monitoring program that monitors the condition of structures and structural supports that are within the scope of subsequent license renewal to manage the following aging effects:

- Cracking
- Cracking and distortion
- Cracking, loss of bond, and loss of material (spalling, scaling)
- Cracking, loss of material
- Increase in porosity and permeability, cracking, loss of material (spalling, scaling)
- Increase in porosity and permeability, cracking, loss of strength
- Loss of material
- Loss of material (spalling, scaling) and cracking
- Loss of mechanical function
- Loss of preload
- Loss of sealing
- Reduction in concrete anchor capacity
- Reduction of foundation strength and cracking
- Reduction or loss of isolation function

This program consists of periodic visual inspection and monitoring 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, and other documents) will be detected, the extent of degradation determined and evaluated, and corrective actions taken prior to loss of intended functions. Inspections also include seismic joint fillers, elastomeric materials; and steel edge supports and steel bracings associated with masonry walls, and periodic evaluation of groundwater chemistry and opportunistic inspections for the condition of below grade concrete. Quantitative results (measurements) and qualitative information from periodic inspections are trended with photographs and surveys for the type, severity, extent, and progression of degradation. The acceptance criteria are derived from applicable consensus codes and standards. For concrete structures, the program includes personnel qualifications and quantitative acceptance criteria of ACI 349.3R, “Evaluation of Existing Nuclear Safety-Related Concrete Structures.”

Qualified inspectors identify changes that could be indicative of Alkali-Silica Reaction (ASR). If indications of ASR development are identified, the evaluation considers the potential for ASR development in concrete that is within the scope of the *Structures Monitoring* program (A1.34), the *ASME Section XI, Subsection IWL* program (A1.30), or the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (A1.35).

A1.35 INSPECTION OF WATER-CONTROL STRUCTURES ASSOCIATED WITH NUCLEAR POWER PLANTS

The *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program is an existing condition monitoring program, which is implemented as part of the *Structures Monitoring* program (A1.34), and manages the following aging effects:

- Cracking
- Cracking; loss of bond; loss of material (spalling, scaling)
- Increase in porosity and permeability; loss of strength
- Loss of material
- Loss of material (spalling, scaling) and cracking
- Loss of material; loss of form

This program consists of inspection and surveillance of raw-water control structures associated with emergency cooling systems or flood protection. The program also includes structural steel and structural bolting associated with water-control structures. In general, parameters monitored are consistent with Section C.2 of Regulatory Guide 1.127, Revision 1 (March 1978), “Inspection of Water-Control Structures Associated with Nuclear Power Plants,” and quantitative measurements are recorded for findings that exceed the acceptance criteria for applicable parameters monitored or inspected. The inspections of the water-control structures within the scope of subsequent licensing renewal are conducted at a frequency not to exceed five years.

A1.36 PROTECTIVE COATING MONITORING AND MAINTENANCE

The *Protective Coating Monitoring and Maintenance* program is an existing mitigative and condition monitoring program that manages loss of coating integrity of Service Level I coatings inside Containment. The program maintains and monitors the aging of Service Level 1 coatings consistent with Regulatory Guide 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants." The program consists of guidance for selection, application, inspection, and maintenance of protective coatings.

Maintenance of Service Level I coatings applied to carbon steel and concrete surfaces inside Containment (e.g., steel liner, structural steel, supports, penetrations, and concrete walls and floors) will serve to prevent or minimize the loss of material of carbon steel components due to corrosion and aids in decontamination, but these coatings are not credited for managing the effects of corrosion for the carbon steel Containment liner and components. This program ensures that the Service Level I coatings maintain adhesion so as to not affect the intended function of the emergency core cooling systems suction strainers.

The program also provides controls over the amount of unqualified coatings. Unqualified coating may fail in a way to affect the intended function of the emergency core cooling systems suction strainers. Therefore, the quantity of degraded and unqualified coating is controlled and assessed periodically to ensure that the amount of unqualified coating in the primary containment is kept within acceptable design limits to support the post-accident operability of the emergency core cooling systems.

A1.37 ELECTRICAL INSULATION FOR ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

The *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is an existing condition monitoring program that manages the aging effect of reduced electrical insulation resistance of the accessible electrical cable and connection electrical insulation material subject to an adverse localized environment.

Accessible in-scope electrical cable and connection insulation material is visually inspected for cable and connection insulation surface anomalies indicating signs of reduced electrical insulation resistance. If visual inspections identify degraded or damaged conditions, then testing is performed for evaluation.

Should testing be deemed necessary, a sample of each cable and connection insulation material type found within the adverse localized environment will be tested. Testing may include thermography and other proven condition monitoring test methods applicable to the cable and connection insulation material. The electrical cable and connection insulation material test results are to be within the acceptance criteria, as identified in the procedures.

A1.38 ELECTRICAL INSULATION FOR ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS USED IN INSTRUMENTATION CIRCUITS

The *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program is an existing performance monitoring program that manages the aging effects of reduced electrical insulation resistance of the electrical cables and connections (cable system) electrical insulation material used in circuits with sensitive, high-voltage, low-level current signals that are subjected to adverse localized environments caused by temperature, radiation, or moisture.

The program applies to the Containment high range radiation monitor system, the post-accident neutron monitoring system and the excore neutron monitoring system.

The evaluations of the electrical insulation material are completed prior to the subsequent period of extended operation and at least once every ten years thereafter.

A1.39 ELECTRICAL INSULATION FOR INACCESSIBLE MEDIUM-VOLTAGE POWER CABLES NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

The *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is an existing condition monitoring program that manages the aging effect of reduced electrical insulation resistance or degraded dielectric strength of inaccessible medium-voltage cables exposed to significant moisture.

The program applies to inaccessible or underground (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations) non-EQ medium-voltage power (operating voltage of 2kV to 35kV) cables within the scope of subsequent license renewal 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.

Periodic actions are taken to prevent non-EQ inaccessible medium-voltage power cables from being exposed to significant moisture. Accessible cable conduit ends and manholes/vaults associated with the cables included in this program are inspected for water accumulation and the water is drained, as necessary.

A1.40 ELECTRICAL INSULATION FOR INACCESSIBLE INSTRUMENT AND CONTROL CABLES NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

The *Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new condition monitoring program that will manage the aging effect of reduced electrical insulation resistance or degraded dielectric strength of inaccessible instrument and control cables exposed to significant moisture.

This program will apply to inaccessible or underground (e.g., installed in buried conduit, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations) non-EQ instrument and control cable within the scope of subsequent license renewal 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.

Periodic actions will be taken to prevent non-EQ inaccessible instrument and control cables from being exposed to significant moisture. Accessible cable conduit ends and manholes/vaults associated with the cables included in this program are inspected for water collection and the water is drained, as necessary.

Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

A1.41 ELECTRICAL INSULATION FOR INACCESSIBLE LOW-VOLTAGE POWER CABLES NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

The *Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new condition monitoring program that will manage the aging effect of reduced electrical insulation resistance or degraded dielectric strength of inaccessible low-voltage power cables exposed to significant moisture.

The program will apply to inaccessible or underground (e.g., installed in buried conduit, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations) non-EQ low-voltage power cables (operating voltage less than 2kV), within the scope of subsequent license renewal 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.

Periodic actions will be taken to prevent inaccessible low-voltage power cables from being exposed to significant moisture. Accessible cable conduit ends and manholes/vaults associated with the cables included in this program are inspected for water accumulation and the water is drained, as necessary.

Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

A1.42 METAL ENCLOSED BUS

The *Metal Enclosed Bus* program is an existing condition monitoring program that manages the aging effects of increased electrical resistance of metal enclosed bus (MEB) electrical connections; reduced electrical insulation resistance of MEB electrical insulation and insulators; surface cracking, crazing, scuffing, dimensional change (e.g., “ballooning” and “necking”), shrinkage, discoloration, hardening, and loss of strength of MEB enclosure assembly elastomers; and loss of material of the external surface of MEB enclosure assemblies. Bus enclosure assemblies (internal and external), bus bar insulation, bus bar insulating supports, and bus bar bolted connections are included in the scope of the program.

Visual inspection of accessible metal enclosed bus internal surfaces is performed to detect age-related degradation, including cracks, corrosion, foreign debris, excessive dust buildup, and evidence of moisture intrusion. Accessible metal enclosed bus insulating material is visually inspected for signs of embrittlement, cracking, chipping, melting, swelling, discoloration, or surface contamination, which may indicate overheating or aging degradations. The accessible internal bus insulating supports are visually inspected for structural integrity and signs of cracks. Accessible metal enclosed bus external surfaces are visually inspected for loss of material due to general, pitting, and crevice corrosion.

Accessible elastomers (e.g., gaskets, boots, and sealants) are inspected for degradation, including surface cracking, crazing, scuffing, dimensional change (e.g., “ballooning” and “necking”), shrinkage, discoloration, hardening and loss of strength. A sample of accessible bolted connections is inspected for increased electrical resistance of connection by measuring connection resistance using a micro-ohmmeter.

The first inspection, including measuring connection resistance, will be completed prior to the subsequent period of extended operation and at least every ten years thereafter.

A1.43 FUSE HOLDERS

The Fuse Holders program is an existing condition monitoring program that manages increased electrical resistance of connection of the metallic clamps and reduced electrical insulation resistance of the fuse holder electrical insulation material.

The Fuse Holders program applies to fuse holders within the scope of subsequent license renewal that are located outside of active equipment and that require aging management.

The Fuse Holders program utilizes visual inspection and testing to identify age-related degradation for both fuse holder electrical insulation material and fuse holder metallic clamps.

A1.44 ELECTRICAL CABLE CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

The *Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new condition monitoring program that will manage the aging effect of increased electrical resistance of the electrical cable connections (metallic parts).

The program will perform a one-time test, on a representative sample of electrical connections, to confirm the absence of loosening of connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion and oxidation. The following factors will be considered for sampling: voltage level (medium and low-voltage), circuit loading (high loading), connection type, and location (high temperature, high humidity, vibration, etc.). Depending on the findings of the one-time test, subsequent testing may have to be performed within ten years of initial testing.

Non-EQ electrical cable connections (metallic parts) associated with cables within the scope of subsequent license renewal will be tested prior to the subsequent period of extended operation. The specific type of test to be performed will be determined based on the type of connection and will be a proven test method for detecting increased resistance of the connection.

Twenty percent of a connector type population with a maximum sample of 25 constitutes a representative connector sample size. Otherwise a technical justification of the methodology and sample size used for selecting components under test will be included as part of the program's documentation.

As an alternative to testing accessible cable connections that are covered with heat shrink tape, sleeving, insulating boots, etc., a visual inspection of electrical insulation materials may be implemented. When this alternative visual inspection is used to check cable connections, the inspection will be completed prior to the subsequent period of extended operation, and repeated at least every five years, thereafter. The basis for performing only the alternative visual inspection to monitor age-related degradation of cable connections will be documented.

Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

A1.45 HIGH-VOLTAGE INSULATORS

The *High-Voltage Insulators* program is a new condition monitoring program that will manage loss of material and reduced electrical insulation resistance for insulators credited for recovery of offsite power that are susceptible to airborne contaminants including dust, salt, fog, cooling tower plume, or industrial effluent. This program applies to porcelain, toughened glass, and polymer insulators.

Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

A2 SUMMARY DESCRIPTIONS OF TIME-LIMITED AGING ANALYSIS AGING MANAGEMENT PROGRAMS

A2.1 FATIGUE MONITORING

The *Fatigue Monitoring* program is an existing preventive program that manages cycle-based fatigue of the mechanical or structural components with a fatigue time-limited aging analysis (TLAA) or other analysis that depends on the number of occurrences and severity of transient cycles. This program is used to accept fatigue or other types of cyclical loading TLAAs in accordance with the acceptance criterion in 10 CFR 54.21(c)(1)(iii).

The aging management program monitors and tracks the number of occurrences and severity of design basis transients assessed in the applicable fatigue or cyclical loading analyses for the ASME Code, Class 1 vessels; ASME Code, Section III fatigue waiver analyses, and various ASME Code, Section XI, Appendix C and L evaluations used to validate time between inspections for environmentally-assisted fatigue analyses (CUF_{en} analyses) of sentinel locations in Class 1 piping. The program also monitors applicable design transient parameters (e.g., temperatures and pressures) for the pressurizer and pressurizer surge line during drawing and collapse of a bubble in the pressurizer.

The program manages cumulative fatigue damage or cracking induced by fatigue or cyclic loading in the ASME Code, Class 1 vessels by monitoring and tracking the number of occurrences and severity of the design basis transients. The program also sets applicable acceptance criteria (limits) on these parameters. Therefore, the program has two aspects, one to verify the continued acceptability of existing analyses through cycle counting or parameter monitoring and the other to provide periodically updated evaluations of the analyses to demonstrate that they continue to meet the appropriate limits.

This program also implements appropriate corrective actions (e.g., reanalysis, component inspections, or component or structure repair or replacement activities) when acceptance limits are approached. Plant Technical Specification requirements are not applicable to the scope of this program.

A2.2 NEUTRON FLUENCE MONITORING

The *Neutron Fluence Monitoring* program is an existing condition monitoring program that manages loss of fracture toughness due to neutron fluence of the reactor pressure vessel (RPV) regions for which neutron fluence is projected to exceed 1 x 10^{17} n/cm^2 (E>1MeV) during the subsequent period of extended operation to ensure that applicable reactor pressure vessel neutron irradiation embrittlement analysis will remain within their applicable limits.

This program has two aspects: one to verify the continued acceptability of existing analyses through neutron fluence monitoring and the other to provide periodically updated evaluations of the analyses involving neutron fluence inputs to demonstrate that they continue to meet the appropriate limits defined in the current licensing basis (CLB).

Monitoring is performed in accordance with neutron flux determination methods and neutron fluence projection methods that are defined for the CLB in NRC-approved reports. For fluence monitoring activities that apply to components located in the beltline region of the RPVs, the monitoring methods are performed in a manner that is consistent with the monitoring methodology guidelines in Regulatory Guide 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.” Neutron fluence monitoring methods that are applied to RPV locations outside of the beltline region of the RPVs were justified and are consistent with NRC-approved methodology.

This program's results are compared to the neutron fluence parameter inputs used in the neutron embrittlement analyses for RPV components. This includes but is not limited to the neutron fluence inputs for the RPV upper-shelf energy analyses and equivalent margin analyses, pressure-temperature analyses, and low temperature overpressure protection (LTOP) that are required to be performed in accordance in 10 CFR Part 50, Appendix G requirements, and safety analyses that are performed to demonstrate adequate protection of the RPVs 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 (as applicable to the CLB) includes those for RT_{NDT}.

Reactor vessel surveillance capsule dosimetry data obtained in accordance with 10 CFR Part 50, Appendix H requirements and through implementation of the *Reactor Vessel Material Surveillance* program (A1.19) provides inputs to and have impacts on the neutron fluence monitoring results that are tracked by this program. In addition, regulatory requirements in the plant technical specifications or in specific regulations of 10 CFR Part 50 apply, including those in 10 CFR Part 50, Appendix G; 10 CFR 50.55a; and the PTS requirements in 10 CFR 50.61, as applicable for the CLB.

Reload verification of assumed reactor vessel fluence values on a cycle-by-cycle basis is performed based on calculations of the cumulative average unit capacity factor and cumulative-average-weighted reload Relative (radial) Power Distributions (RPDs) of peripheral core locations.

A2.3 ENVIRONMENTAL QUALIFICATION OF ELECTRIC EQUIPMENT

The *Environmental Qualification of Electrical Equipment* program manages equipment thermal, radiation, and cyclical aging through the use of aging evaluations based on qualification methods given in 10 CFR 50.49. This program implements the EQ requirements in 10 CFR 50.49. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical equipment located in harsh plant environments will perform applicable safety functions in those harsh environments after the effects of in-service aging. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification.

As required by 10 CFR 50.49, environmentally qualified equipment not qualified for the current license term is refurbished or replaced, or has its qualified life extended through reanalysis or ongoing qualification prior to reaching the designated life aging limits established in the evaluation. Aging evaluations for environmentally qualified equipment that specify a qualified life of at least 40 to 60 years are time-limited aging analyses (TLAAs) for subsequent license renewal.

The Environmental Qualification of Electric Equipment program is consistent with the guidance of 10 CFR 50.49; Inspection and Enforcement Bulletin (IEB) 79-01B, “Environmental Qualification of Class 1E Equipment”; “Guidelines for Evaluation of Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors” (DOR Guidelines); NUREG-0588, “Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment;” and IEEE Standard 323-1974, “IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations.”

Reanalysis of an aging evaluation to extend the qualification of equipment qualified under the program requirements of 10 CFR 50.49(e) is performed as part of the EQ program. 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 analytical models used in the reanalysis of an aging evaluation are the same as those previously applied during the prior evaluation. The identification of excess conservatism in electrical equipment service conditions (for example, temperature, radiation, and cycles) used in the prior aging evaluation is the primary method used for a reanalysis. A reanalysis demonstrates that adequate margin is maintained consistent with the original analysis in accordance with 10 CFR 50.49 requiring certain margins and accounting for the unquantified uncertainties established in the EQ aging evaluation of the equipment. Reanalysis of an aging evaluation can be used to extend the environmental qualification of the equipment. If the qualification cannot be extended by reanalysis, the equipment is refurbished, replaced, or requalified prior to exceeding the current qualified life.

When the reanalysis assessed margins, conservatisms, or assumptions do not support reanalysis (e.g., extending qualified life) of environmentally qualified equipment, the use of on-going qualification techniques including condition monitoring or condition based methodologies may be implemented. Ongoing qualification is an alternative means to provide reasonable assurance that equipment environmental qualification is maintained for the subsequent period of extended operation. Ongoing qualification of electric equipment within the scope of the EQ program involves the inspection, observation, measurement, or trending of one or more indicators, which can be correlated to the condition or functional performance of the environmentally qualified equipment.

Accessible passive EQ electrical equipment within the scope of subsequent license renewal will be inspected at least once every ten years to identify EQ electrical equipment subjected to an adverse localized environment with the first inspection performed prior to the subsequent period of extended operation.

A3 EVALUATION SUMMARIES OF TIME-LIMITED AGING ANALYSES

As part of the application for a renewed license, 10 CFR 54.21(c) requires that an evaluation of Time-Limited Aging Analyses (TLAAs) for the subsequent period of extended operation be provided. The following TLAAs, as defined in 10 CFR 54.3, have been identified and evaluated to meet this requirement.

A3.1 IDENTIFICATION OF TIME-LIMITED AGING ANALYSES

10 CFR 54.21(c)(2) requires that the application for a renewed license include a list of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based upon TLAAs as defined in 10 CFR 54.3. It also requires an evaluation that justifies the continuation of these exemptions for the subsequent period of extended operation. There were no exemptions to 10 CFR 50.12 identified that are currently in effect that are based upon or are associated with a TLAA.

The following TLAAs have been identified and evaluated to meet 10 CFR 54.21(c) requirements. Summaries of the TLAAs applicable to the subsequent period of extended operation are included in the following sections:

- Reactor Vessel Neutron Embrittlement Analysis (Section A3.2)
- Metal Fatigue (Section A3.3)
- Environmental Qualification of Electric Equipment (Section A3.4)
- Concrete Containment Tendon Prestress (Section A3.5)
- Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis (Section A3.6)
- Other Plant-Specific Time-Limited Aging Analyses (Section A3.7)

A3.2 REACTOR VESSEL NEUTRON EMBRITTLEMENT ANALYSIS

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 *Reactor Vessel Material Surveillance* program is described in Section A1.19. The ferritic materials of the reactor pressure vessel (RPV) 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 TLAAs. The following RPV neutron embrittlement TLAAs have been identified and evaluated to meet 10 CFR 54.21(c) requirements:

- Neutron Fluence Projections
- Upper-Shelf Energy
- Pressurized Thermal Shock
- Adjusted Reference Temperature
- Pressure Temperature Limits
- Low Temperature Overpressure Protection

A3.2.1 Neutron Fluence Projections

Updated neutron fluence evaluations were performed and documented in WCAP-18015-NP, “Extended Beltline Pressure Vessel Fluence Evaluations Applicable to North Ann Units 1 & 2." RV beltline and extended beltline fast neutron fluences (E > 1.0 MeV) at the end of 80 years of operation were calculated for Units 1 and 2. The analyses methodologies used to calculate the Units 1 and 2 RV fluences satisfy the guidance set forth in Regulatory Guide 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.” These methodologies have been approved by the NRC and are described in detail in WCAP-14040-A, “Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves,” and are documented in UFSAR Section 5.4.3.6, “Irradiation Surveillance Program.” The fluence analyses have been projected to the end of the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

A3.2.2 Upper-Shelf Energy

Appendix G of 10 CFR 50, Paragraph IV.A.1.a, indicates that reactor vessel (RV) beltline materials must have Charpy upper-shelf energy of no less than 75 ft-lb initially, and must maintain Charpy upper-shelf energy 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 upper-shelf energy will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code, “Fracture Toughness Criteria for Protection Against Failure.” For materials outside the beltline, a minimum value of 30 ft-lbs at 10 °F was specified by ASTM E208, and required by ASME Code, Section III, at the time of the initial design and fabrication of Units 1 and 2. The upper shelf energy (USE) analyses for the ferritic steel components (i.e., RV shell plates or forgings, nozzle plates or forgings, and associated pressure retaining welds) in the beltline region of the RV have been updated based on component neutron fluence values that have been projected to the end of the subsequent period of extended operation and the current RV surveillance test data for the facility. As documented in WCAP-18364-NP, “North

Anna Units 1 and 2 Time-Limited Aging Analysis on Reactor Vessel Integrity for Subsequent License Renewal (SLR)," the materials that exceeded the 1.0 × 1017 n/cm^2 (E > 1.0 MeV) threshold at 72 EFPY are evaluated to determine their impact on USE during the proposed subsequent period of extended operation. The forgings and welds corresponding to some inlet and outlet nozzles are predicted to experience neutron fluence greater than 1.0 x 1017 n/cm^2 at the end of the subsequent period of extended operation. However, for conservatism, all the inlet and outlet nozzle materials are considered part of the extended beltline.

For Unit 1, reactor vessel materials are projected to remain at or above the USE screening criterion value of 50 ft-lbs at 72 EFPY.

For Unit 2, the limiting USE value at 72 EFPY is 48.2 ft-lb; this value corresponds to the Intermediate Shell Forging 04. All other Unit 2 reactor vessel materials are projected to remain above the USE screening criterion value of 50 ft-lbs at 72 EFPY.

The Unit 2 Intermediate Shell Forging 04 reactor vessel material, which is projected to drop below 50 ft-lbs USE prior to 72 EFPY, is addressed in the equivalent margins analysis (EMA) performed in PWROG-19047-P, "North Anna Reactor Vessel Low Upper-Shelf Fracture Toughness Equivalent Margin Analysis," to qualify the material at 72 EFPY per 10 CFR 50, Appendix G. The material-specific EMA, which must be submitted to the NRC for review and approval at least three years prior to the USE dropping below 50 ft-lbs was transmitted to the NRC through the PWROG under Letter OG-20-167, dated May 27, 2020. The Unit 2 Intermediate Shell Forging 04 is projected to drop below 50 ft-lbs at 52.3 EFPY, which is projected to occur in 2040. In addition to the material discussed above, for conservatism, PWROG-19047-P includes EMAs for all the following materials at each unit:

- Upper Shell Forging
- Intermediate Shell Forging
- Inlet Nozzle Forgings
- Outlet Nozzle Forgings
- Inlet Nozzle Welds
- Outlet Nozzle Welds

Units 1 and 2 RV nozzle-to-shell welds, nozzle forgings and upper shell forgings were evaluated for equivalent margins of safety per ASME Code, Section XI. The flaw extension and stability criteria of ASME Code, Section XI, Appendix K are satisfied.

The USE TLAA has been projected to the end of the subsequent period of extended operation and is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

A3.2.3 Pressurized Thermal Shock

10 CFR 50.61(b)(1) provides rules for protection against pressurized thermal shock (PTS) events for pressurized water reactors and requires the reference temperature RTPTS for reactor vessel (RV) beltline materials to be less than the PTS screening criteria at the expiration date of the operating license unless otherwise approved by the NRC. All the beltline and extended beltline materials in the Units 1 and 2 RV are below the RTPTS screening criteria values of 270 °F for base metal and/or longitudinal welds, and 300 °F for circumferentially oriented welds through 72 EFPY. The PTS analyses have been projected to the end of the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii)

A3.2.4 Adjusted Reference Temperature

The adjusted reference temperature (ART) of the limiting beltline material is used to adjust the beltline P-T limit curves to account for irradiation effects. 10 CFR 50, Appendix G, defines the fracture toughness requirements for the life of the vessel. Regulatory Guide 1.99 provides the methodology for determining the ART of the limiting material. RTNDT was evaluated in accordance with PWROG-18005-NP, “Determination of Unirradiated RTNDT and Upper-Shelf Energy Values of the North Anna Units 1 and 2 Reactor Vessel Materials.” The limiting ART values at 50.3 EFPY for Unit 1, 52.3 EFPY for Unit 2 and 72 EFPY for both units are less than the limiting ART values used to develop the existing P-T limit curves. The ART analyses have been projected to the end of the period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

A3.2.5 Pressure-Temperature Limits

10 CFR 50 Appendix G requires that the RV 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 RV is exposed to increased neutron irradiation, its fracture toughness is reduced. The P-T limits must account for the anticipated RV fluence.

According to NUREG-2192, Section 4.2.2.1.4, the P-T limits for the subsequent period of extended operation need not be submitted as part of the subsequent license renewal application since the P-T limits are required to be updated through the 10 CFR 50.90, “Application for Amendment of License, Construction Permit, or Early Site Permit,” licensing process when necessary for P-T limits that are located in the Technical Specifications. The P-T limit curves for normal heatup and cooldown of the primary reactor coolant system for Units 1 and 2 were previously developed in WCAP-15112, “North Anna Units 1 and 2 WOG Reactor Vessel 60-Year Evaluation Minigroup Heatup and Cooldown Limit Curves for Normal Operation.” The P-T limit curves for 72 EFPY were developed in WCAP-18363, “North Anna Units 1 and 2 Heatup and Cooldown Limit Curves for Normal Operation.” Per WCAP-18363-NP, the applicability of the current P-T limit curves may be extended through the subsequent period of extended operation, because the current Technical Specifications P-T limit curves bound the new P-T limit curves.

The *Reactor Vessel Material Surveillance* program (A1.19) will ensure that updated P-T limits based upon updated ART values will be submitted to the NRC for approval prior to exceeding the current terms of applicability for Units 1 and 2. Since the P-T limits will be updated through 10 CFR 50.90 at a later, appropriate date, the effects of aging on the intended function(s) of the RVs will be adequately managed for the period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

A3.2.6 Low Temperature Overpressure Protection

The Units 1 and 2 low temperature overpressure protection (LTOP) system is required by Technical Specification Limited Condition for Operation 3.4.12. Two pressurizer power operated relief valves (PORV) are used to provide the automatic relief capability during the design basis mass input and the design basis heat input transients to automatically prevent the reactor coolant system pressure from exceeding the pressure temperature limit curves based on 10 CFR 50, Appendix G.

In WCAP-18363-NP, “North Anna Units 1 and 2 Heatup and Cooldown Limit Curves for Normal Operation,” the maximum allowable LTOP system pressurizer PORV setpoint was calculated to be ≤ 400 psig when any RCS cold leg temperature is ≤ 180°F and ≤ 558 psig when any RCS cold leg temperature is ≤ 280°F for the Units 1 and 2 through the subsequent period of extended operation. The calculation was performed in accordance with the WCAP-14040-A, “Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit,” methodology using critical LTOP input parameters, updated results of the design basis mass injection and heat injection transients, and the limiting axial flaw steady state ASME Code, Section XI, Appendix G limits from WCAP-15112, “North Anna Units 1 and 2 WOG Reactor Vessel 60-Year Evaluation Minigroup Heatup and Cooldown Limit Curves for Normal Operation,” that were determined to be applicable through 72 EFPY for Units 1 and 2.

The evaluation showed that the current Technical Specifications value of ≤ 375 psig when any RCS cold leg temperature is ≤ 180°F and ≤ 540 psig when any RCS cold leg temperature is ≤ 280°F maintain margin to the maximum allowable settings calculated for the subsequent period of extended operation throughout the range of LTOP applicability. Therefore, the current LTOPS settings are bounding and can be maintained through 72 EFPY for Units 1 and 2.

The LTOP system setpoint and enabling temperature have been projected to the end of the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

A3.3 METAL FATIGUE

Fatigue analyses are required on components designed to ASME Code, Section III, Class 1 and piping designed to USAS (ANSI) B31.7, Class I. Also, certain other codes such as ASME Code, Section III, Class 2 and 3, USAS (ANSI) B31.1, and ASME Code, Section VIII, 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 that are likely to have fatigue TLAAs within the current licensing basis (CLB) that would require evaluation for the subsequent period of extended operation. Searches were performed to identify these and any other potential fatigue TLAAs within the current licensing bases for Units 1 and 2. Each of the potential TLAAs were evaluated against the six TLAA screening criteria specified in 10 CFR 54.3. Those that were identified as fatigue TLAAs are evaluated in the following Subsections:

- Transient Cycle Projections for 80 years (Section A3.3.1)
- ASME Code, Section III, Class I Fatigue Analyses (Section A3.3.2)
- ANSI B31.1 Allowable Stress Analyses (Section A3.3.3)
- Environmental- Assisted Fatigue (Section A3.3.4)
- Reactor Vessel Internals Fatigue Analyses (Section A3.3.5)
- High Energy Line Break Fatigue (Section A3.3.6)

A3.3.1 Transient Cycle Projections for 80 years

Fatigue analyses are based upon explicit numbers and amplitudes of thermal and pressure transients. UFSAR Table 5.2-4 and Section 18.4.2 provides a listing of design transients and associated design cycles. The intent of the design basis transient definitions is to bound a wide range of possible events with varying ranges of severity in temperature and pressure. The existing fatigue analyses are based upon the original number of design cycles (40 years) and are postulated to bound 60 years of service. Since the fatigue analyses are based upon a number of cycles postulated to bound sixty years of service for the current license basis, these analyses constitute a TLAA.

Baseline cycle counts were projected to an 80-year operating life based on the actual accumulation history over the 10-year period from November 8, 2007 to November 8, 2017. Since most nuclear power plants, including NAPS Units 1 and 2, have experienced a significant declining trend in accumulation of transients over time, transient projections based on recent operating experience provide an appropriate basis for future projections. Therefore, each monitored design transient was evaluated to determine if the recent 10-year trend had a consistent cycle accumulation rate. The 10-year rate was used to extrapolate the projected number of future occurrences beginning November 8, 2017 and ending at 80 years of plant operation. The end of 80-year life is April 2058 for Unit 1 and August 2060 for Unit 2. The projected cycles for 80 years of plant operation were less than the 40-year design cycles (CLB cycles) used in the fatigue analyses. Therefore, the fatigue analyses for ASME Code, Section III components remain valid for the subsequent period of extended operation. In order to ensure the design cycles remain bounding in the ASME Code, Section III fatigue analyses, the Fatigue Monitoring program (B3.1) will track cycles for significant fatigue transients and ensure corrective action is taken prior to potentially exceeding fatigue design limits. A Condition Report will be initiated based upon an administrative limit of 90% of the fatigue cycles.

A3.3.2 ASME Code, Section III, Class I Fatigue Analyses

Fatigue analyses are performed per ASME Code, Section III. Each analysis is required to demonstrate that the Cumulative Usage Factor (CUF) for the component will not exceed the Code design limit 1.0 when the component is exposed to all postulated transients.

The following ASME Code, Section III components were assessed for impact on fatigue:

- Control Rod Drive Mechanism (CRDM)
- Pressurizer (including Nozzle Weld Overlays)
- Reactor Coolant Pump
- Reactor Vessel
- Steam Generator (including Unit 1 Inlet Nozzle Weld Overlays)
- Pressurizer Surge Line
- Class I B31.7 Piping
- ASME Code, Section III, Component Fatigue Waivers
- Loop Stop Isolation Valves

In addition, a detailed fatigue evaluation is not required if components conform to the waiver of fatigue requirements per ASME Code, Section III. These fatigue waivers depend on the numbers of anticipated transients over the life of the plant and therefore constitute TLAAs.

The 40-year design cycles (CLB cycles) were postulated to bound 80 years of plant operations. Therefore, the fatigue analyses and fatigue waivers remain valid for the subsequent period of extended operation. In order to ensure the design cycles remain bounding in the fatigue analyses and fatigue waivers, the Fatigue Monitoring program (Section A2.1) will track cycles for significant fatigue transients listed in the UFSAR, Table 5.2-4 and Section 18.4.2, and ensure corrective action is taken prior to potentially exceeding fatigue design limits.

The effects of fatigue on the intended function(s) of ASME Code, Section III components will be adequately managed by the Fatigue Monitoring program (Section A2.1) for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A3.3.3 ANSI B31.1 Allowable Stress Analyses

The reactor coolant system's primary loop piping is constructed in accordance with USAS (ANSI) B31.7, “Nuclear Power Piping,” 1969 Edition with 1970 and 1971 Addenda and Class II, Class III, and, the balance-of-plant piping in scope for subsequent license renewal are analyzed to the requirements of ANSI B31.1, “Power Piping.” As identified in USAS (ANSI) B31.7, Class I piping is designed for the cumulative effect of two or more types of stress cycles by use of a cumulative usage factor (CUF). Fatigue for Class I piping is addressed as a TLAA in Section A.3.3.2.

For piping systems designed in accordance with USAS (ANSI) B31.1, explicit analyses of cumulative fatigue usage are not required. Instead, cyclic loading is considered in a simplified manner in the design process. Allowable thermal stresses are reduced using a stress range reduction factor based on the number of anticipated thermal cycles expected during the component operating lifetime. Stress range reduction factors are specified in USAS (ANSI) B31.1, Table 102.3.2(c). No reduction of allowable stresses is required for piping that is subjected to less than 7,000 equivalent full temperature cycles during plant service. The evaluations for required stress reduction factors are implicit fatigue analyses because they are based on the number of fatigue cycles anticipated for the life of the component, therefore, they are TLAAs requiring evaluation for the subsequent period of extended operation.

USAS (ANSI) B31.1 systems are generally subject to continuous steady state operation and operating temperatures vary only during plant heatup and cooldown, during plant transients, or during periodic testing. Portions of piping systems designed in accordance with ANSI B31.1 requirements that are attached to the reactor coolant system or other power cycle related systems are subject to a similar number or fewer cycles as the reactor coolant system. These include condensate, containment vacuum, extraction steam, feedwater, primary and secondary gas supply, main steam, reactor coolant, steam drains, and vacuum priming systems. Portions of some of these systems are normally isolated from the normal power cycle and would experience fewer cycles than those portions at the system boundary. The expected transients for these systems are much less than 7,000 cycles for 80 years of plant operation.

Portions of the following systems, designed in accordance with ANSI B31.1 requirements, are affected by thermal and pressure transients that are different than the reactor coolant and power cycles discussed above: alternate AC, auxiliary boilers, auxiliary steam, blowdown, chilled water, chemical and volume control, emergency diesel generator, high radiation sampling, heating and ventilation, residual heat, security, and sampling system.

The basis for cycle projections have been reviewed for these systems to validate that the projected cycles for 80 years of operation remains less than 7,000 cycles. The number of cycles for each of these piping systems and heat exchangers is projected to be less than 7,000 for 80 years of plant operation.

The USAS (ANSI) B31.1 allowable stress analyses remain valid for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A3.3.4 Environmental- 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) must be examined for a set of sample critical components for the plant. This sample set includes the locations identified in NUREG/CR-6260 and additional plant-specific component locations in the reactor coolant pressure boundary if they may be more limiting than those considered in NUREG/CR-6260. Additional limiting locations were identified through an environmental fatigue screening evaluation. The environmentally-assisted fatigue (EAF) screening evaluation reviewed the CLB fatigue evaluations for all ASME Code, Section III reactor coolant pressure boundary components and USAS (ANSI) B31.7, Class I piping, including the NUREG/CR-6260 locations, to determine the lead indicator (also referred to as sentinel) locations for EAF.

The sentinel locations are listed below:

- RV outlet nozzles (NUREG/CR-6260 location)
- RV inlet nozzles and support pads (NUREG/CR-6260 location)
- RV shell transition (NUREG/CR-6260 location)
- 6-inch branch nozzle Safety Injection - Cold Leg
- 12-inch branch nozzle Accumulator - Cold Leg
- 3-inch branch nozzle - Cold Leg
- Steam generator tubes
- Pressurizer spray nozzle weld overlay, safe end
- Hot leg surge nozzle - bounding location (NUREG/CR-6260 location)
- Pressurizer surge nozzle weld overlay, safe end

For sentinel ASME Code, Section III components with environmentally-assisted fatigue usage (CUF_{en}) greater than 1.0, ASME Code, Section III, NB-3200 calculations were prepared to remove conservatisms used in the analysis of record, thereby reducing the CUF_{en} to less than 1.0. The effects of fatigue on the intended functions of these ASME Code, Section III components will be managed by the Fatigue Monitoring program (Section A2.1) through the use of cycle counting.

For sentinel piping locations, Dominion has elected to manage the effects of fatigue by application of the ASME Section XI Inservice Inspections, Subsections IWB, IWC, AND IWD program (Section A1.1) during the subsequent period of extended operation based on results of flaw tolerance evaluation conducted per the guidance of ASME Code, Section XI, Non-mandatory

Appendix L. NUREG-2192 permits inspections as a management method for fatigue as long as a flaw tolerance evaluation is performed to determine the acceptable time between inspections. The ASME Code, Section XI, Appendix L crack growth evaluation is used in conjunction with calculated allowable flaw sizes to determine the required inspection interval for a postulated flaw in the piping at the bounding location. For a postulated initial flaw, crack growth is simulated until the flaw has reached the allowable flaw depth or the end of the subsequent period of extended operation, whichever comes first.

In-service inspections of the Appendix L piping will be performed at a 10-year inspection frequency. Each weld in the inspection population will be ultrasonically inspected once prior to turning on the clock for the re-inspection schedule associated with the Appendix L evaluations. Going forward after the first ultrasonic inspection, one weld in each of the four groups will be ultrasonically inspected every ten years.

Fatigue of the steam generator tubes will be managed by the Steam Generators program (Section A1.10).

The effects of fatigue on the intended functions of ASME Code, Section III components and piping that contact reactor coolant will be managed by the Fatigue Monitoring program (Section A2.1), the ASME Section XI Inservice Inspections, Subsections IWB, IWC, AND IWD program (Section A1.1) and the Steam Generators program (Section A1.10) through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A3.3.5 Reactor Vessel Internals Fatigue Analyses

The RV internals were designed before ASME Code, Section III, Division 1, Subsection NG was established. Therefore, no CUF values were calculated as part of the original RV internals design. However, as part of engineering evaluations to support Units 1 and 2 operations at MUR power uprate conditions, updated structural evaluations were performed for the upper and lower core plates to demonstrate that they would maintain their structural integrity at proposed power uprate conditions. The lower and upper core plates are not part of the reactor coolant system pressure boundary. As part of the structural evaluations, fatigue analyses of the upper and lower core plates were performed to the 1989 edition of ASME Code, Section III, Division 1, Subsection NG. Fatigue analyses that consider transient cycles that occur over the life of the plant constitute TLAAs. The analysis of record fatigue CUF results are less than 1.0.

The 40-year design cycles (CLB cycles) were postulated to bound an 80-year operating period. Therefore, the reactor vessel internals fatigue analyses remain valid for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A3.3.6 High Energy Line Break Fatigue

The selection of Class 1 piping HELB locations depends on usage factors, which will remain valid as long as the assumed numbers of cycles are not exceeded. The Fatigue Monitoring program (Section A2.1) ensures that the analytical bases of the HELB locations are maintained or that a HELB analysis for the new locations with a CUF greater than 0.1 is performed.

The effects of fatigue on the intended function(s) of Class 1 piping HELB locations will be adequately managed by the Fatigue Monitoring program (Section A2.1) for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A3.4 ENVIRONMENTAL QUALIFICATION OF ELECTRIC EQUIPMENT

Thermal, radiation, and cyclical aging analyses of plant electrical and I&C components, developed to meet 10 CFR 50.49 requirements, have been identified as time-limited aging analyses (TLAAs). The NRC nuclear station environmental qualification (EQ) requirements in 10 CFR 50.49 require that an EQ program be established to demonstrate that certain electrical equipment located in harsh plant environments is qualified to perform applicable safety functions 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 loss-of-coolant accident (LOCA), high energy line break (HELB) or post-LOCA radiation. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification.

The *Environmental Qualification of Electric Equipment* program (A2.3) will manage the effects of aging for EQ equipment through the subsequent period of extended operation in accordance with 10 CFR 50.49(c)(1)(iii). The program meets the requirements of 10 CFR 50.49 for the applicable electrical equipment important to safety. Reanalysis of an aging evaluation to extend the qualifications of equipment is performed on a routine basis as part of the EQ program. Important attributes for the reanalysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, ongoing qualification, and corrective actions if acceptance criteria are not met.

If the qualification cannot be extended by reanalysis, the equipment must be refurbished, replaced, or requalified prior to exceeding the period for which the current qualification remains valid. A reanalysis is to be performed in a timely manner such that sufficient time is available to refurbish, replace, or requalify the equipment if the reanalysis is unsuccessful.

Unit 1 was evaluated against the DOR Guidelines and the basis for Equipment Qualification is Inspection and Enforcement Bulletin (IEB) 79-01B, “Environmental Qualification of Class 1E Equipment,” and IEEE Standard 323-1974 “IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations,” as codified by 10 CFR 50.49. The basis for Unit 2 is IEEE Standard 323-1974 and NUREG-0588, “Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment,” Category II, as codified by 10 CFR 50.49.

The Environmental Qualification of Electrical Equipment program ensures that the aging effects will be managed and that EQ equipment will continue to perform its intended function for the subsequent period of extended operation. Aging effects addressed by the EQ program will therefore be managed for the subsequent period of extended operation and are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii).

Accessible passive EQ electrical equipment within the scope of subsequent license renewal will be inspected at least once every ten years to identify EQ electrical equipment subjected to an adverse localized environment with the first inspection performed prior to the subsequent period of extended operation.

A3.5 CONCRETE CONTAINMENT TENDON PRESTRESS

Not applicable

A3.6 CONTAINMENT LINER PLATE, METAL CONTAINMENTS, AND PENETRATIONS FATIGUE ANALYSIS

A3.6.1 Containment Liner Plate

The accumulated fatigue effects of all applicable liner loading conditions are evaluated based on cycles of operating pressure variations, cycles of operating temperature variations, and design earthquake cycles. The anticipated operating pressure variations were extrapolated for an 80-year operating period and determined to be acceptable. The number of design cycles was conservatively increased to account for the subsequent period of extended operation. Therefore, the Containment liner is adequate for an 80-year operating period as currently designed. The analyses associated with the Containment liner plate have been revised and projected to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

A3.6.2 Metal Containments

Not applicable

A3.6.3 Containment Penetrations Fatigue Analysis

There are no TLAAs for Containment penetrations. The penetrations are designed for a one-time load, which is equal to the collapse loads of the pipe. The stresses due to the normal operating conditions are below the endurance limit. Therefore, the penetrations will not fail due to fatigue. This evaluation remains valid for the subsequent period of extended operation.

A3.7 OTHER PLANT-SPECIFIC TIME-LIMITED AGING ANALYSES

A3.7.1 Crane Load Cycle Limits

The design standard number of full-capacity lifts far exceeds the number expected of each machine for a 80-year life, even with a significant number of unforeseen lifts. The lifting machine designs therefore remain valid for the period of extended operation. These TLAAs are dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

A3.7.2 Reactor Coolant Pump Flywheel Fatigue Crack Growth Analysis

Fatigue crack initiation and growth in reactor coolant pump (RCP) flywheels was evaluated for the subsequent period of extended operation and documented in PWROG-17011-NP, “Update for Subsequent License Renewal: WCAP-14535A, 'Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination,' and WCAP-15666-A, 'Extension of Reactor Coolant Pump Motor Flywheel Examination,'” which confirms that the analysis of WCAP-14535A and WCAP-15666-A remains appropriate. The fatigue crack growth calculations assumed 6000 cycles of RCP start/stop for 80 years of plant life which bounds the projected cycle count of 1200. The RCP fatigue analysis remains valid for the subsequent period of extended operation and the TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

A3.7.3 Leak-Before-Break

10 CFR 50 General Design Criterion 4 allows use of leak-before-break technology for excluding from the design basis the dynamic effects of postulated ruptures in primary coolant loop piping in PWRs. WCAP-11163-P, Revision 1, “Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for North Anna Units 1 and 2 Nuclear Power Plants for the Subsequent License Renewal Program (80 Years) Leak-Before-Break Evaluation,” demonstrated compliance with leak-before-break (LBB) technology for the reactor coolant system piping for an 80-year plant life based on a plant specific analysis that showed all LBB conditions and margins are satisfied. It is therefore concluded that dynamic effects of reactor coolant system primary loop pipe breaks need not be considered in the structural design basis. The LBB analysis has been projected to the end of the subsequent period of extended operation and the TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

A3.7.4 Spent Fuel Pool Liner Fatigue Analysis

A design calculation has been identified which documents that the spent fuel pool liner design meets general industry criteria. A revised calculation includes a fatigue analysis based on the number of thermal cycles corresponding to an 80-year plant operating term. The thermal stresses in the spent fuel pool liner due to conservatively assumed temperature gradients and thermal cycles during an 80-year plant operating term satisfy ASME Code fatigue criteria. Therefore, the revised calculations are projected through the subsequent period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

A3.7.5 Piping Subsurface Flaw Evaluations

Piping subsurface flaws were detected during in-service inspection activities and evaluated in 1984. Flaw tolerance conclusions of the piping subsurface flaw evaluations have been projected to the end of the subsequent period of extended operation. The piping flaw TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

A3.7.6 Reactor Coolant Pump Code Case N-481

ASME Code Case N-481 allows the replacement of volumetric examinations of primary loop pump casings with fracture mechanics-based integrity evaluations supplemented by specific visual examinations. The fracture mechanics integrity assessment in PWROG-17033-NP-A, “Update for Subsequent License Renewal: WCAP-13045, “Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems,” Revision 1,” which updated the analysis in WCAP-13045, demonstrated that the visual inspections, in lieu of volumetric inspections, for pump casings remain valid for an 80-year life. WCAP-15555, “A Demonstration of Applicability of ASME Code Case N-481 to the Primary Loop Pump Casings of the North Anna and Surry Units 1 and 2 for the License Renewal Program,” demonstrated that the North Anna Units 1 and 2 RCP casings are bounded by the evaluations and conclusions in WCAP-13045 and PWROG-17033-NP-A, both for the crack stability analysis [screening loadings (forces, moments, J_{app}, and T_{app}) and limiting material fracture toughness values (J_{1c}, T_{mat}, and J_{max})] and the fatigue crack growth analysis [transient cycles specified and loadings used]. The TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(i).

A3.7.7 Cracking Associated With Weld Deposited Cladding

Reactor vessel underclad cracking involves cracks in base metal forgings immediately beneath austenitic stainless steel cladding which are created as a result of the weld-deposited cladding process. PWROG-17031-NP updated the 60-year fatigue crack growth analysis in WCAP-15338-A and confirmed the analysis remains appropriate for 80 years of operation. The crack growth analysis has been projected to the end of the subsequent period of extended operation and the TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(ii).

A3.7.8 Steam Generator Tube Wear Evaluation

WCAP-18503-P, “Resolution of North Anna Power Station Units 1 & 2 Time-Limited Aging Analyses for Subsequent License Renewal,” shows that for the increase the operating term from 60 years to 80 years, the calculated tube wear remains acceptable. The steam generator tube wear will be managed by the *Steam Generators* program (B2.1.10) using the existing steam generator eddy current inspection consistent with NEI 97-06, “Steam Generator Program Guidelines” in accordance with 10 CFR 54.21(c)(iii).

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A4 Subsequent License Renewal Commitments

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
1	*ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program	The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to require inspections be performed for the following: a. Welds associated with sentinel locations assessed under ASME Code, Section XI, Appendix L include the safety injection 6-inch diameter RCS cold leg nozzles. One safety injection cold leg nozzle is to be inspected once per 10 years for either Unit 1 or Unit 2. b. The pressurizer spray nozzle stainless steel-to-safe-end weld is to be inspected once per 10 years for each unit. 2. Procedures will be revised to require periodic volumetric inspections of the steam generator feedwater nozzle thermal sleeves.	B2.1.1	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
2	*Water Chemistry* program	The *Water Chemistry* program is an existing preventive program that is credited.	B2.1.2	Ongoing
3	*Reactor Head Closure Stud Bolting* program	The *Reactor Head Closure Stud Bolting* program is an existing condition monitoring program that is credited.	B2.1.3	Ongoing
4	*Boric Acid Corrosion* program	The *Boric Acid Corrosion* program is an existing condition monitoring program that is credited.	B2.1.4	Ongoing
5	*Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program	The *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program is an existing condition monitoring program that is credited.	B2.1.5	Ongoing
6	*Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* program	The *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* program is an existing condition monitoring program that is credited.	B2.1.6	Ongoing

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
7	*PWR Vessel Internals* program	The *PWR Vessel Internals* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to provide guidance for inspections of the following reactor vessel internal components in accordance with the referenced report for each item: a. Control rod guide tube (CRGT) lower flange weld (MRP-227, Revision 1-A, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines") b. CRGT guide plates (cards) (MRP-227, Revision 1-A) c. Core barrel upper flange weld (UFW) (MRP-227, Revision 1-A) d. Core barrel lower girth weld (LGW) (MRP-227, Revision 1-A) e. Core barrel middle axial weld (MAW) and lower axial weld (LAW) (MRP-227, Revision 1-A) f. Core barrel upper axial weld (UAW) (MRP-227, Revision 1-A) g. Core barrel upper girth weld (UGW) (MRP-227, Revision 1-A) h. Core barrel lower flange weld (LFW) (MRP-227, Revision 1-A) i. Baffle-edge bolts (MRP-227, Revision 1-A) j. Baffle plates (MRP-227, Revision 1-A) k. Baffle-former bolts (MRP-227, Revision 1-A) l. Barrel-former bolts (MRP-227, Revision 1-A) m. Bottom-mounted instrumentation column bodies (MRP-227, Revision 1-A) n. Lower support column bodies (MRP-227, Revision 1-A) o. Lower support column bolts (MRP-227, Revision 1-A) p. Clevis insert bolts (MRP 2018-022, "Transmittal of MRP-191 Screening, Ranking, and Categorization Results and Interim Guidance in Support of Subsequent License Renewal at U.S. PWR Plants") q. Clevis insert dowels (MRP 2018-022) r. Stellite™ wear surface on radial support keys (MRP 2018-022) s. Stellite™ wear surface on clevis inserts (MRP 2018-022) t. Fuel alignment pins for lower core plate (MRP 2018-022) u. Fuel alignment pins for upper core plate (MRP 2018-022) 2. Procedures will be revised to provide guidance for inspections of the CRGT continuous section sheaths and C-tubes in accordance with WCAP-17451-P, Revision 2, "Reactor Internals Guide Tube Wear – Westinghouse Domestic Fleet Operational Projections". 3. Procedures will be revised to provide acceptance criteria for inspection results for the following reactor vessel internal components in accordance with MRP-227, Revision 1-A: a. Thermal shield flexures b. Lower support forging c. Upper core plate	B2.1.7	Program, accounting for the impacts of a gap analysis, will be implemented 6 months prior to the subsequent period of extended operation, or alternatively, a plant-specific program may be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
7	*PWR Vessel Internals* program	4. Procedures will be revised to provide guidance for one-time inspections of the core barrel MAW and LAW in accordance with 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".	B2.1.7	Program, accounting for the impacts of a gap analysis, will be implemented 6 months prior to the subsequent period of extended operation, or alternatively, a plant-specific program may be implemented 6 months prior to the subsequent period of extended operation.
8	*Flow-Accelerated Corrosion* program	The *Flow-Accelerated Corrosion* program is an existing condition monitoring program that will be enhanced as follows: 1. An Engineering evaluation will be performed for systems that have been excluded from FAC monitoring activities due to no flow, or infrequently used lines with a total operating and testing time that is less than 2% of the plant operating time during the first period of extended operation. The purpose of the Engineering evaluation is to confirm the scope of components that will qualify for the exclusion being extended into the subsequent period of extended operation. The Engineering evaluation and subsequent modeling changes for tracking FAC monitoring activities will be completed prior to entering the subsequent period of extended operation.	B2.1.8	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
9	*Bolting Integrity* program	The *Bolting Integrity* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedure(s) will be enhanced to: a. include inspections of pressure-retaining bolting in inaccessible areas when they become accessible by means such as excavation, dewatering, or shielding/barrier removal, and b. include a requirement during opportunistic maintenance activities to document the condition of bolt heads and threads. 2. Procedure(s) will be developed and/or revised to provide instructions for performing inspections of pressure boundary bolting for plant locations that preclude detection of joint leakage including bolting in submerged environments, bolting for air or gas systems, and bolting for piping systems not normally pressurized as follows: a. Submerged closure bolting is visually inspected for loss of material during maintenance activities. In this case, bolt heads are inspected when made accessible, and bolt threads are inspected when joints are disassembled. In each 10-year period during the subsequent period of extended operation, for each unit, a representative sample of bolt heads and threads is inspected up to a maximum of 19 bolts for each material and environment combination. If opportunistic maintenance activities will not provide access to 20% of the population (for a material/environment combination) up to a maximum of 19 bolt heads and threads over a 10-year period, then periodic pump vibration measurements are taken and trended. b. For air or gas systems, inspections are performed consistent with that of submerged closure bolting. Closure bolting for air or gas systems is visually inspected for loss of material during maintenance activities. In this case, bolt heads are visually inspected when made accessible, and bolt threads are visually inspected when joints are disassembled. In each 10-year period during the subsequent period of extended operation, for each unit, a representative sample of bolt heads and threads is inspected up to a maximum of 19 bolts for each material and environment combination. If opportunistic maintenance activities will not provide access to 20% of the population (for a material/environment combination) up to a maximum of 19 bolt heads and threads over a 10-year period, then soap bubble testing will be performed. c. For piping systems not normally pressurized, the torque of the bolting will be checked to the extent that the closure bolting is not loose. In each 10-year period during the subsequent period of extended operation, for each unit, a representative sample of bolt heads and threads is inspected up to a maximum of 19 bolts for each material and environment combination.	B2.1.9	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
9	*Bolting Integrity* program	3. Procedure(s) will be developed and/or revised to evaluate sampling-based inspections against plant-specific acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, sampling frequencies will be evaluated and adjusted as determined by the corrective action program. Bolting that is unsuitable for continued use will be replaced. 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, additional inspections will be conducted if one of the inspections does not meet acceptance criteria. The number of increased inspections is determined in accordance with the site's 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 and environment combination is inspected, whichever is less. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of inspections. Additional samples are inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections include inspections of components with the same material and environment combination for each unit and are completed within the 10-year inspection interval in which the original inspection was conducted.	B2.1.9	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
10	*Steam Generators* program	The *Steam Generators* program is an existing condition monitoring program that is credited.	B2.1.10	Ongoing
11	*Open-Cycle Cooling Water* program	The *Open-Cycle Cooling Water* program is an existing condition monitoring program that is credited.	B2.1.11	Ongoing

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
12	*Closed Treated Water Systems* program	The *Closed Treated Water Systems* program is an existing condition monitoring program that will be enhanced as follows: 1. A new procedure will be developed to specify that in each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed for the various sample populations (each material, water treatment program, and aging effect combination). If opportunistic inspections will not fulfill the minimum number of inspections by the end of each 10-year period, the program owner will initiate work orders as necessary to request additional inspections. A representative sample of 20% of the population (defined as components having the same material, water treatment program, and aging effect combination) or a maximum of nineteen components per population at each unit will be inspected. The new procedure will specify that the inspections focus on the bounding or lead components most susceptible to aging due to time in service, and severity of operating conditions. 2. A new procedure will be developed to specify that, where practical, the rate of any degradation is evaluated and projected until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The sampling bases (e.g., selection, size, frequency) will be adjusted as necessary based on the projection. 3. A new procedure will be developed to specify that additional inspections will be performed if any inspections do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted.	B2.1.12	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
13	*Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program	The *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program is an existing condition monitoring program that is credited.	B2.1.13	Ongoing
14	*Compressed Air Monitoring* program	The *Compressed Air Monitoring* program is an existing condition monitoring program that is credited.	B2.1.13	Ongoing

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
15	*Fire Protection* program	The *Fire Protection* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures for fire barrier penetration seals, fire barriers, fire damper assemblies, and fire doors will be revised to require, where practical, identified degradation to be projected until the next scheduled inspection. 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 subsequent period of extended operation based on the projected rate and extent of degradation. 2. Procedures will be revised to require that if degradation is detected within the inspection sample of penetration seals, the scope of the inspection is expanded to include additional seals in accordance with the Corrective Action Program. Additional inspections would be 20% of each applicable inspection sample; however, additional inspections would not exceed five. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the Corrective Action Program.	B2.1.15	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
16	*Fire Water System* program	The *Fire Water System* program is an existing condition monitoring and performance monitoring program that will be enhanced as follows: 1. Procedures will be developed or revised to specify: a. Standpipe and system flow tests for hose stations at the hydraulically most limiting locations for each zone of the system on a five-year interval to demonstrate the capability to provide the design pressure at required flow b. Wet pipe main drain testing will be performed on 20% of the standpipes and risers every 18 months on a refueling cycle basis. Acceptance criteria will be based upon monitoring flowing pressures from test to test to determine if there is a 10% reduction in full flow pressure when compared to previously performed tests. The Corrective Action Program will determine the cause and necessary corrective action. c. If a flow test or a main drain test does not meet acceptance criteria due to current or projected degradation additional tests are conducted. The number of increased tests is determined in accordance with the corrective action process; 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 in which the original test was conducted. If subsequent tests do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of tests. The additional tests include at least one test at the other unit with the same material, environment, and aging effect combination. d. Main drains for the standpipes associated with hose stations within the scope of subsequent license renewal will also be added to main drain testing procedures.	B2.1.16	Program will be implemented and inspections or tests begin 5 years before the subsequent period of extended operation. Inspections or tests that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
16	*Fire Water System* program	2. Procedures will be revised to perform internal visual inspections of sprinkler and deluge system piping to identify internal corrosion, foreign material, and obstructions to flow. Follow-up volumetric examinations will be performed if internal visual inspections detect an unexpected level of degradation due to corrosion product deposition. If organic or foreign material, or internal flow blockage that could result in failure of system function is identified, then an obstruction investigation will be performed within the Corrective Action Program that includes removal of the material, an extent of condition determination, review for increased inspections, extent of follow-up examinations, and a flush in accordance with NFPA 25, 2011 Edition, Annex D.5, Flushing Procedures. The internal visual inspections will consist of the following: a. Wet pipe sprinkler systems - 50% of the wet pipe sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote sprinkler, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. During the next five-year inspection period, the alternate systems previously not inspected shall be inspected. b. Pre-action sprinkler systems - pre-action sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. c. Deluge systems - deluge systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. 3. Procedures will be revised to perform system flow testing at five-year intervals with flows representative of those expected during a fire. A flow resistance factor (C-factor) will be calculated to compare and trend the friction loss characteristics to the results from previous flow tests. 4. Procedures will be revised to address recurring internal corrosion with the use of Low Frequency Electromagnetic Technique (LFET) or a similar technique on 100 feet of piping during each refueling cycle to detect changes in the pipe wall thickness. The procedure will specify thinned areas found during the LFET screening be followed up with pipe wall thickness examinations to ensure aging effects are managed and wall thickness is within acceptable limits. In addition to the pipe wall thickness examination, the performance of opportunistic visual inspections of the fire protection system will be required whenever the fire water system is opened for maintenance. The piping age, time in service, and susceptibility to corrosion should be considered in determining sample location priorities. 5. The Unit 2 lube oil purification and hydrogen seal oil piping will have the piping pitch adjusted to improve drainage. A drain valve will be installed on the Unit 2 hydrogen seal oil fire protection piping to drain the line after system testing or initiation. As part of the drainage reconfiguration, visual inspections and wall thickness measurements will be performed to identify unexpected degradation. Piping with unexpected degradation will be replaced. 6. The activity of the jockey pump (i.e., an increase in the number of pump starts or run time of the pump) will be monitored consistent with the “detection of aging effects” program element of NUREG-2191, Section XI.M41. 7. At each unit, a sample of 3% or a maximum of ten wet pipe sprinklers with no more than four sprinklers per structure shall be tested. Testing is based on a minimum time in service of fifty years and severity of operating conditions for each population.	B2.1.16	Program will be implemented and inspections or tests begin 5 years before the subsequent period of extended operation. Inspections or tests that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
17	*Outdoor and Large Atmospheric Metallic Storage Tanks* program	The *Outdoor and Large Atmospheric Metallic Storage Tanks* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to require periodic visual inspections of the RWSTs and CCTs be performed at each refueling outage to confirm that the mastic sealant at the RWSTs and CCTs insulation and concrete foundation interface is intact. The visual inspections of the sealant will be supplemented with physical manipulation to detect any degradation. If there are any identified flaws, the mastic sealant will be repaired or replaced, and follow-up examination of the tank's surfaces will be conducted if deemed appropriate. An inspection of the caulk at the tank and concrete foundation interface will be included in the sample when the RWSTs and CCTs external insulation is removed and the caulk will be sampled for external surface visual examinations ten years before the subsequent period of extended operation. Results will be forwarded to Engineering for evaluation and the need for additional inspections will be determined based on projected corrosion rates. 2. Procedures will be revised to require visual and surface examination of the exterior surfaces of the RWSTs, CATs, and CCTs be performed to identify any loss of material or cracking. A minimum of either 25 one-square foot sections or 20% of the surface area of insulation will be required to be removed to permit inspection of the exterior surface of each tank. The procedure will specify that sample inspection points be distributed in such a way that inspections occur near the bottoms, at points where structural supports, pipe, or instrument nozzles penetrate the insulation, and where water could collect such as on top of stiffening rings. If no unacceptable loss of material or cracking is observed, subsequent external surface examinations of insulated tanks will inspect for indications of damage to the jacketing, evidence of water intrusion through the insulation, or evidence of damage to the moisture barrier of tightly adhering insulation. 3. Procedures will be revised to require one-time thickness measurements of a sample of the Unit 1 and Unit 2 ECSTs interior wall prior to the subsequent period of extended operation to assess potential degradation due to leakage identified from the missile shield into the pipe penetration area in the Auxiliary Feedwater Pump House. The samples will examine the ECSTs interior vertical steel shell region from the bottom of the tank along the pipe penetration area, extending six feet vertically up from the tank, as this is a region potentially most susceptible to degradation. The inspection results will be projected to the end of the subsequent period of extended operation to confirm the ECSTs intended functions will be maintained throughout the subsequent period of extended operation based on the projected rate of degradation. Any degradation not meeting acceptance criteria will require periodic 10-year thickness measurements and a sample expansion along the leakage path consistent with the observed degradation. The upper manway and lower manway gaskets will be replaced during the one-time inspection.	B2.1.17	Program will be implemented and inspections or tests begin 10 years before the subsequent period of extended operation. Inspections or tests that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
17	*Outdoor and Large Atmospheric Metallic Storage Tanks* program	4. Procedures will be revised to require volumetric examination thickness measurements of the bottom of the RWSTs and CCTs be performed each 10-year period during the subsequent period of extended operation starting ten years before the subsequent period of extended operation. Results will be forwarded to Engineering for evaluation and the need for additional inspections will be determined based on projected corrosion rates. 5. A new procedure will be developed to specify that additional inspections be performed consistent with NUREG-2191. If any inspections do not meet the acceptance criteria, additional inspections are conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending). a. For inspections where only one tank of a material, environment, and aging effect was inspected, all tanks in that grouping are inspected. b. For other sampling based inspections there will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at the other unit. The additional inspections will be completed within the interval (i.e., 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the first half of the next inspection interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the Corrective Action Program. However, for one-time inspections that do not meet acceptance criteria, inspections are subsequently conducted at least at 10-year inspection intervals.	B2.1.17	Program will be implemented and inspections or tests begin 10 years before the subsequent period of extended operation. Inspections or tests that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
18	*Fuel Oil Chemistry* program	The *Fuel Oil Chemistry* program is an existing condition monitoring program that will be enhanced as follows: 1. The *Fuel Oil Chemistry* program scope will be revised to include the security diesel generator fuel oil day tank. 2. Procedure(s) will be revised or developed to drain, clean internally to the extent practical, visually inspect internal surfaces (if physically possible), and perform tank bottom thickness measurements of the following tanks: • Emergency diesel generator fuel oil day tanks (procedures are currently available to drain and clean on demand) • SBO diesel generator fuel oil day tank (new procedure needed) • Diesel-driven fire pump 2 fuel oil storage tank (new procedure needed) • Security diesel generator fuel oil day tank (new procedure needed) The procedure(s) will require that if evidence of degradation is observed during visual inspection, or if visual inspection is not possible, volumetric inspections will be performed. The draining, cleaning and inspection of each tank will be performed at least once during the 10-year period prior to the subsequent period of extended operation and at least once every 10 years during the subsequent period of operation. Procedure(s) will be revised or developed to require an Engineering evaluation be performed to evaluate and trend visual and volumetric (if degradation is detected during inspections) tank inspection results. Unacceptable inspection results will be documented in the Corrective Action Program. Thickness measurements will be evaluated against the design thickness and corrosion allowance. The rate of degradation is evaluated and projected until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection frequency will be adjusted, as necessary, based on the projection. 3. Procedures will be revised or developed to perform a one-time draining, cleaning and internal visual inspection of the security diesel generator fuel oil supply tank between 30 and 40 years of service. Any degradation found during the internal visual inspection will be addressed by the Corrective Action Program. If degradation is observed, volumetric measurements will be performed. 4. Procedures will be updated to clarify the need to specifically monitor and trend water and biological activity in addition to particulates.	B2.1.18	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.
19	*Reactor Vessel Material Surveillance* program	The *Reactor Vessel Material Surveillance* program is an existing condition monitoring program that is credited.	B2.1.19	Ongoing

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
20	*One-Time Inspection* program	The *One-Time Inspection* program is a new condition monitoring program 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. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.	B2.1.20	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.
21	*Selective Leaching* program	The *Selective Leaching* program is a new condition monitoring program that will monitor components constructed of materials which are susceptible to selective leaching. The selective leaching program includes a one-time inspection for susceptible components exposed to closed cycle cooling water and treated water environment since plant-specific operating experience has not revealed selective leaching in these environments, as well as opportunistic and periodic inspections for susceptible components exposed to raw water, waste water, and soil (which may include groundwater) environments. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.	B2.1.21	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
22	*ASME Code Class 1 Small-Bore Piping* program	The *ASME Code Class 1 Small-Bore Piping* program is a new condition monitoring program that augments the existing ASME Code, Section XI requirements and is applicable to ASME Code Class 1 small-bore piping and systems with a NPS diameter less than 4 inches and greater than or equal to 1 inch. This program provides for volumetric examination of a sample of full penetration (butt) welds and partial penetration (socket) welds in Class 1 piping to manage cracking due to stress corrosion cracking or thermal or vibratory fatigue loading. Volumetric examinations will employ techniques that have been demonstrated to be capable of detecting flaws and discontinuities in the examination volume of interest. The extent and schedule for volumetric examination is based on plant-specific operating experience and whether actions have been implemented that effectively mitigate the cause(s) of any past cracking. The program provides for a one-time inspection of a sample of the population of welds (butt welds or socket welds) for plants that have not experienced cracking or have experienced cracking but have implemented corrective actions, such as a design change, to effectively mitigate the cause(s) of the cracking. The program provides for periodic inspection of a sample of the population of welds (butt welds or socket welds) that have experienced cracking and have not implemented corrective actions to effectively mitigate the cause(s) of the cracking. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.	B2.1.22	Program will be implemented and inspections are completed within 6 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior of extended operation.
23	*External Surfaces Monitoring of Mechanical Components* program	The *External Surfaces Monitoring of Mechanical Components* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to specify walkdowns will be performed at a frequency not to exceed one refueling cycle. Since some surfaces are not readily visible during both plant operations and refueling outages, surfaces will be inspected when they are made accessible and at intervals that ensure the components' intended functions are maintained. 2. Procedures will be revised to specify that visual inspections of elastomers and flexible polymers will cover 100% of accessible component surfaces. The minimum surface area for tactile inspections of elastomers and flexible polymers will be at least 10% of the accessible surface area.	B2.1.23	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
23	*External Surfaces Monitoring of Mechanical Components* program	3. A new procedure will be developed to specify the following to manage cracking of stainless steel, nickel-alloy, and copper alloy (>15% Zn) components and cracking and loss of material of insulated outdoor/indoor components exposed to condensation populations: a. In each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed. Inspections for cracking will be performed from each of the stainless steel, nickel-alloy, and copper alloy (>15% Zn) component populations every 10 years. Examinations are conducted on 20% of the surface area unless the component is measured in linear feet, such as piping. Alternatively, any combination of a minimum of 25 one-foot axial length sections and components is inspected. In addition, for each unit, both the inner and outer nickel-alloy reactor vessel flange leakage monitor tubes will be inspected every 10 years. For insulated outdoor components and indoor components exposed to condensation, following insulation removal, 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 one-foot axial length determination is inspected for loss of material and cracking. Alternatively, any combination of a minimum of 25 one-foot axial length sections and components for each material type is inspected. The new procedure will specify that the inspections focus on the components most susceptible to aging because of time in service, severity of operating conditions, and lowest design margin. b. Additional inspections will be performed if any sampling-based inspections to detect cracking in stainless steel, nickel-alloy, and copper alloy (>15% Zn) components do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted. 4. Procedures will be revised to evaluate and project the rate of degradation until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection sampling bases (e.g., selection, size, frequency) will be adjusted as necessary based on the projection. 5. Procedures will be revised to specify that, where practical, acceptance criteria are quantitative (e.g., minimum wall thickness). For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions.	B2.1.23	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
24	*Flux Thimble Tube Inspection* program	The *Flux Thimble Tube Inspection* program is an existing condition monitoring program that is credited.	B2.1.24	Ongoing
25	*Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program	The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to require inspection of elastomeric and flexible polymeric components for the following: • Surface crazing, scuffing, loss of sealing, blistering, and dimensional change (e.g., “ballooning” and “necking”) • Loss of wall thickness • Exposure of internal reinforcement (e.g., reinforcing fibers, mesh, or underlying metal) for reinforced elastomers 2. Procedures will be revised to specify that visual inspection of elastomeric and flexible polymeric components is supplemented by tactile inspection to detect hardening or loss of suppleness. The minimum surface area for tactile inspections will be at least 10% of the accessible surface area. 3. Procedures will be revised to specify that follow-up volumetric examinations are performed where irregularities that could be indicative of an unexpected level of degradation are detected for steel components exposed to raw water, raw water (potable), or waste water. 4. Procedure(s) will be revised or developed to specify the following: a. In each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed for the various sample populations (each material, environment, and aging effect combination). If opportunistic inspections will not fulfill the minimum number of inspections by the end of each 10-year period, the program owner will initiate work orders as necessary to request additional inspections. A representative sample of 20% of the population (defined as components having the same material, environment, and aging effect combination) or a maximum of 19 components per population at each unit will be inspected. The new procedure will specify that the inspections focus on the bounding or lead components most susceptible to aging due to time in service and severity of operating conditions. b. The rate of degradation will be evaluated and projected until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection sampling bases (e.g., selection, size, frequency) will be adjusted as necessary based on the projection.	B2.1.25	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
25	*Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program	5. Procedure(s) will be revised or developed to specify the following: a. In each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed for the various sample populations (each material, environment, and aging effect combination). If opportunistic inspections will not fulfill the minimum number of inspections by the end of each 10-year period, the program owner will initiate work orders as necessary to request additional inspections. A representative sample of 20% of the population (defined as components having the same material, environment, and aging effect combination) or a maximum of 19 components per population at each unit will be inspected. The new procedure will specify that the inspections focus on the bounding or lead components most susceptible to aging due to time in service and severity of operating conditions. b. The rate of degradation will be evaluated and projected until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection sampling bases (e.g., selection, size, frequency) will be adjusted as necessary based on the projection. c. Additional inspections will be performed if any sampling-based inspections do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination are inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the next refueling outage interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval. 6. The existing inspections of the Unit 1 and Unit 2 bearing cooling system, performed under the Corrective Action Program, will be enhanced to require performance of a minimum of 10 piping wall thickness measurements at each Unit with a frequency not to exceed two refueling cycle intervals. Locations with a wall thickness of less than 50% will be selected and augmented as necessary considering prior inspection results, extent of degradation, rate of degradation, and timing of the next inspection. 7. Procedure(s) will be revised or developed to specify that, where practical, acceptance criteria are quantitative (e.g., minimum wall thickness). For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions.	B2.1.25	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
26	*Lubricating Oil Analysis* program	The *Lubricating Oil Analysis* program is an existing preventive program that is credited.	B2.1.26	Ongoing
27	*Buried and Underground Piping and Tanks* program	The *Buried and Underground Piping and Tanks* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to obtain pipe-to-soil potential measurements for piping in the scope of SLR during the next soil survey within 10 years prior to entering the subsequent period of operation. 2. The following service water CP subsystems will be refurbished and reconnected before the last five years of the inspection period prior to entering the subsequent period of extended operation. a. The service water 'D' CP subsystem b. The service water 'C' CP subsystem associated with the buried carbon steel piping of the fuel oil system for the emergency electrical power system 3. Procedures will be revised to specify that cathodic protection surveys use the -850 mV polarized potential, instant off criterion specified in NACE SP0169-2007 for steel piping acceptance criteria unless a suitable alternative polarization criteria can be demonstrated. Alternatives will include the -100 mV polarization criteria, -750 mV criterion (soil resistivity is greater than 10,000 ohm-cm to less than 100,000 ohm-cm), -650 mV criterion (soil resistivity is greater than 100,000 ohm-cm), or verification of less than 1 mpy loss of material rate. a. The external loss of material rate is verified: • Every year when verifying the effectiveness of the cathodic protection system by measuring the loss of material rate. • Every 2 years when using the 100 mV minimum polarization. • Every 5 years when using the -750 or -650 mV criteria associated with higher resistivity soils. The soil resistivity is verified every 5 years. b. As an alternative to verifying the effectiveness of the cathodic protection system every five years, soil resistivity testing is conducted annually during a period of time when the soil resistivity would be expected to be at its lowest value (e.g., maximum rainfall periods). Upon completion of ten annual consecutive soil samples, soil resistivity testing can be extended to every five years if the results of the soil sample tests consistently have verified that the resistivity did not fall outside of the range being credited (e.g., for the -750 mV relative to a CSE, instant off criterion, measured soil resistivity values were greater than 10,000 ohm-cm). c. When using the electrical resistance corrosion rate probes: • The individual determining the installation of the probes and method of use will be qualified to NACE CP4, "Cathodic Protection Specialist" or similar • The impact of significant site features and local soil conditions will be factored into placement of the probes and use of the data	B2.1.27	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
28	*Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program	The *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to require baseline inspections (100% of accessible coatings/linings) of the following tanks, piping, and miscellaneous components within the scope of subsequent license renewal and inspection intervals will not exceed those specified in NUREG-2191 Table XI.M42-1, Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers: • Condensate polishing Powdex tanks • Pressurizer relief tanks • Chilled water mechanical chiller cooler (channel head) • Circulating water inlet and outlet waterbox piping • Chemical and volume control flow transmitters (emergency borate header flow and boric acid to blend system flow) • Fire protection isolation valve • Drains - bldg. services piping 2. Procedures will be revised to include as an alternative to repair, rework, or removal, internal coatings/linings exhibiting indications of peeling and delamination. The component may be returned to service if: a. Physical testing is conducted to ensure that the remaining coating is tightly bonded to the base metal, b. the potential for further degradation of the coating is minimized, (i.e., any loose coating is removed, the edge of the remaining coating is feathered), c. adhesion testing using ASTM International Standards endorsed in RG 1.54 (e.g., pull-off testing, knife adhesion testing) is conducted at a minimum of three sample points adjacent to the defective area, d. an evaluation is conducted of the potential impact on the system, including degraded performance of downstream components due to flow blockage and loss of material or cracking of the coated component, and e. follow-up visual inspections of the degraded coating are conducted within two years from detection of the degraded condition, with a re-inspection within an additional two years, or until the degraded coating is repaired or replaced.	B2.1.28	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
28	*Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program	3. Procedures will be revised to require additional inspections 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 of components constructed of the same material and exposed to the same environment. The number of increased inspections will be determined in accordance with the Corrective Action Program. However, there are no fewer than five additional inspections or each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. When inspections are based on the percentage of piping length, an additional 5% of the total length will be inspected. The timing of the additional inspections will be based on the severity of the degradation identified and will be commensurate with the potential for loss of intended function. However, in all cases, the additional inspections will be 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 refueling outage interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval. 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 will include inspections with the same material, environment, and aging effect combination at Unit 1 and Unit 2. 4. Procedures will be revised to require inspection frequencies for internal coatings/linings of in-scope piping and piping components are performed on a frequency consistent with Table XI.M42-1, various frequencies from 4-12 years.	B2.1.28	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
29	*ASME Section XI, Subsection IWE* program	The *ASME Section XI, Subsection IWE* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to augment visual examinations with surface examinations (or other applicable technique) to manage cracking in the pressure retaining portions of the fuel transfer tube, fuel transfer tube enclosure, fuel transfer tube blind flange, dissimilar metal weld penetrations, and high-temperature piping penetrations. Surface examinations will be performed once during each 10-year interval. 2. Procedures will be revised to perform a one-time volumetric examination of metal liner surfaces that are inaccessible from one side if triggered by plant-specific operating experience. The trigger for this supplemental examination is plant-specific occurrence or recurrence of measurable metal liner corrosion (base metal material loss exceeding 10% of nominal plate thickness) initiated on the inaccessible side or areas, identified since the date of issuance of the first renewed license. This supplemental volumetric examination consists of a sample of one-foot square locations that include both randomly-selected and focused areas most likely to experience degradation based on operating experience and/or other relevant considerations such as environment. Any identified degradation is addressed in accordance with the applicable provisions of the *ASME Section XI, Subsection IWE* program. The sample size, locations, and any needed scope expansion (based on findings) for this one-time set of volumetric examinations should be determined on a plant-specific basis to demonstrate statistically with 95% confidence that 95% of the accessible portion of the containment liner is not experiencing corrosion degradation with greater than 10% loss of nominal thickness. 3. Plant procedures will be revised to specify that successive inspections will be sequenced, evaluated, and re-examined in accordance with ASME Code, Section XI, Subsection IWE, Article IWE-2420. Examination results will be compared with recorded results of prior inservice examinations and evaluated for acceptance in accordance with ASME Code, Section XI, Subsection IWE, Article IWE-3120.	B2.1.29	Program enhancements are implemented 6 months prior to the subsequent period of extended operation and if triggered by plant-specific operating experience, a one-time supplemental volumetric examination by sampling randomly selected as well as focused locations susceptible to loss of thickness due to corrosion of containment shell or liner that is inaccessible from one side is completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.
30	*ASME Section XI, Subsection IWL* program	The *ASME Section XI, Subsection IWL* program is an existing condition monitoring program that is credited.	B2.1.30	Ongoing

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
31	*ASME Section XI, Subsection IWF* program	The *ASME Section XI, Subsection IWF* program is an existing condition monitoring program that will be enhanced as follows: 1. 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 exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. 2. Procedures will be revised to specify that, for high-strength bolting greater than one inch nominal diameter within the scope of the *ASME Section XI, Subsection IWF* program, volumetric examination comparable to that of ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 will be performed to detect cracking in addition to the VT-3 examination. In each 10-year period during the subsequent period of extended operation, a representative sample of 20% of the population or a maximum of 19 high-strength bolts per unit will be inspected for IWF supports located in an "air" environment. 3. Procedures will be revised to specify a one-time inspection within five years prior to entering the subsequent period of extended operation of an additional 5% of the sample populations for Class 1, 2, and 3 piping supports. The additional supports will be selected from the remaining population of IWF piping supports and will include components that are most susceptible to age-related degradation. 4. Procedures will be revised to require that if a component support does not exceed the acceptance standards of IWF-3400 but is 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.	B2.1.31	Program will be implemented and a one-time inspection of an additional 5% of the sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports is conducted within 5 years prior to the subsequent period of extended operation, and are to be completed prior to the subsequent period of extended operation, are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.
32	*10 CFR 50, Appendix J* program	The *10 CFR 50, Appendix J* program is an existing condition monitoring program that is credited.	B2.1.32	Ongoing
33	*Masonry Walls* program	The *Masonry Walls* program is an existing condition monitoring program that is credited.	B2.1.33	Ongoing
34	*Structures Monitoring* program	The *Structures Monitoring* program Is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to include inspection of the following structures that are within the scope of subsequent license renewal: Administration Building (aka Office Building), Decontamination Building, Domestic Water Treatment Building, Heater Boiler Room, Maintenance Building, New Fuel Receiving Building, Waste Disposal (Clarifier) Building, Waste Solids Building, 17-ton Carbon Dioxide tank foundation, and Backup 34.5 kV Circuit Power Poles (Switchyard to the Reserve Station Service Transformers). Baseline inspections for the added structures will be performed under the enhanced program in order to establish quantitative inspection data prior to conduct of periodic inspections in the subsequent period of extended operation. The baseline inspections will include baseline inspections of the masonry walls in the Administration Building, Decontamination Building, Domestic Water Treatment Building, and the Maintenance Building.	B2.1.34	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
34	*Structures Monitoring* program	2. Procedures will be revised to specify that structural components inspected include structural bolting, anchor bolts and embedments, component support members, pipe whip restraints and jet impingement shields, transmission towers, panels and other enclosures, racks, sliding surfaces, sump and pool liners, electrical cable trays and conduits, tube tracks, trash racks associated with water-control structures, electrical duct banks, manholes, doors, penetration seals, seismic joint filler and other elastomeric materials. 3. Procedures will be revised to specify that aluminum and stainless steel structural components such as louvers, cable trays, conduits, and structural supports will be monitored for cracking due to SCC that could lead to the reduction or loss of their intended function. 4. Procedures will be revised to specify that elastomeric vibration isolators, structural sealants, and seismic joint fillers will be monitored for cracking, loss of material, and hardening that could lead to the reduction or loss of their intended function. Visual inspection of elastomeric elements is supplemented by tactile inspection to detect hardening if the intended function is suspect. 5. Procedures will be revised to specify that accessible sliding surfaces will be monitored for indications of excessive loss of material due to corrosion or wear and debris or dirt that could restrict or prevent sliding of the surfaces. 6. Procedures will be enhanced to specify that evaluations of neutron shield tank findings consider its structural support function for the reactor pressure vessel.	B2.1.34	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
35	*Inspection of Water-Control Structures Associated with Nuclear Power Plants* program	The *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to include the Circulating Water Intake Tunnel Header and the Discharge Tunnel Seal Pit within the scope of the program. 2. Procedures will be revised to specify underwater inspections or dewatering to permit visual inspections for submerged structures, on a frequency not to exceed five years.	B2.1.35	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
36	*Protective Coating Monitoring and Maintenance* program	The *Protective Coating Monitoring and Maintenance* program is an existing mitigative and condition monitoring program that is credited.	B2.1.36	Ongoing
37	*Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program	The *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to add the requirement to identify adverse localized environments through plant operational experience reviews, communication with maintenance, operations, and radiation protection personnel, and the use of environmental surveys for determining each of the most limiting cable and connection electrical insulation plant environments (e.g., caused by temperature, radiation, moisture, or contamination.)	B2.1.37	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
37	*Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program	2. Procedures will be revised to add a list of structures/areas to perform/conduct the visual inspections of cables and connections. 3. Procedures will be revised to add the requirement to perform a review of previously identified and mitigated adverse localized environments cumulative aging effects applicable to in-scope cable and connection electrical insulation. 4. Procedures will be revised to add a description of testing methodology: Should testing be deemed necessary based on unacceptable visual indications of surface anomalies, a sample size of 20% of each cable and connection insulation material type found within the adverse localized environment with a maximum sample size of 25 will be tested. The following factors will be considered in the development of the cable and connection insulation test sample: environment including identified adverse localized environments (high temperature, high humidity, vibration, etc.), voltage level, circuit loading, connection type, location (high temperature, high humidity, vibration, etc.), and insulation material. Testing may include thermography and other proven condition monitoring test methods applicable to the cable and connection insulation. Testing as part of an existing maintenance, calibration or surveillance program may be credited. The technical basis for the sample selected is provided. 5. Procedures will be revised to add the requirement that if anomalies are found during the visual inspection process, they will be addressed through the Corrective Action Program. 6. Procedures will be revised to add the requirement to verify that the test results for electrical cable and connection insulation material are to be within the acceptance criteria, as identified in the procedures. 7. Procedures will be revised to add the requirement to include the performance of an Engineering evaluation of unacceptable test results and visual indications of cable and connection electrical insulation abnormalities. The evaluation will consider the age and operating environment of the component, as well as the severity of the abnormality and whether such an abnormality has previously been correlated to degradation of cable or connection insulation. Corrective actions include, but are not limited to, testing, shielding, or otherwise mitigating the environment or relocation or replacement of the affected cables or connections. When an unacceptable condition or situation is identified, a determination is made as to whether the same condition or situation is applicable to additional in-scope accessible and inaccessible cables or connections (extent of condition).	B2.1.37	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
38	*Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program	The *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program is an existing condition monitoring program that will be enhanced as follows: 1. A new procedure will be developed to add testing of the post-accident neutron monitoring system cables and connections external to Containment to the Program. The procedure will evaluate reduced electrical insulation resistance by measuring cable resistance and capacitance. 2. The Nuclear Instrumentation test procedures will be enhanced to specify the acceptance criteria..	B2.1.38	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
38	*Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program	3. Procedures will be enhanced to include corrective actions and a requirement for performance of an Engineering evaluation when cable system test results do not meet the acceptance criteria. Results of the Engineering evaluation will determine if the test frequency needs to be increased.	B2.1.38	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
39	*Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program	The *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to inspect and dewater, if required, the in-scope manholes after event driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding. 2. Procedures will be revised to add a step stating that automatic or passive drainage features of manholes are operating properly. 3. Procedures will be revised to add a step that includes a requirement for testing medium-voltage cables that are exposed to significant moisture to determine the condition of the electrical insulation. 4. Procedures will be revised to add cables from RSST \`B' and \`C' to Bus 1G and Bus 2G, and associated handholes, to the scope of the program and perform inspections, dewatering, and testing with the first inspection scheduled prior to the subsequent period of extended operation. 5. Procedures will be revised to add a step to evaluate adjusting the inspection frequency of manholes based on plant-specific operating experience over time with water collection. 6. A plant-specific inaccessible medium-voltage cable test matrix will be created that documents inspection methods, test methods, and acceptance criteria for the in-scope inaccessible medium-voltage power cables based on OE. Testing will be conducted at least every six years. 7. Procedures will be revised to include a requirement to review visual inspection and physical test results that are trendable and repeatable to provide additional information on the rate of cable or connection insulation degradation.	B2.1.39	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
40	*Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program	The *Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new condition monitoring program that will manage the effects of reduced electrical insulation resistance or degraded dielectric strength of non-EQ, in scope, inaccessible (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations), instrument and control cables, exposed to significant moisture. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.	B2.1.40	Program will be implemented 6 months prior to the subsequent period of extended operation.
41	*Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program	The *Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new condition monitoring program that will manage the effects of reduced electrical insulation resistance or degraded dielectric strength of non-EQ, in scope, inaccessible (e.g., installed in buried conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations), low-voltage power cables (operating voltage less than 2 kV), exposed to significant moisture. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.	B2.1.41	Program will be implemented 6 months prior to the subsequent period of extended operation.
42	*Metal-Enclosed Bus* program	The *Metal-Enclosed Bus* program is an existing condition monitoring program that will be enhanced as follows: 1. A new procedure will be created to add the MEB connecting ‘A’ Reserve Station Service Transformer to Bus 1G and Bus 2G to the scope of the program and perform inspections and testing on a ten year frequency with the first inspection scheduled prior to the subsequent period of extended operation. 2. Procedures will be revised to add a step for inaccessible sections of bus duct that requires engineering to provide guidance for performance of electrical testing of connections using an ohmmeter and for performance of visual inspection of the bus duct using a borescope. 3. Inspection procedures will be revised to add a note stating that 20% of the accessible bolted connection population, with a maximum of 25, is a representative sample for increased resistance of connection inspections. 4. Procedures will be revised to require the transmittal of bus connection resistance values to engineering for trending to provide information on the rate of connection degradation.	B2.1.42	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
43	*Fuse Holders* program	The *Fuse Holders* program is an existing condition monitoring program that is credited.	B2.1.43	Ongoing
44	*Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program	The *Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new condition monitoring program that consists of a representative sample of electrical connections tested prior to the subsequent period of extended operation. The results will be evaluated to determine if there is a need for subsequent periodic testing on a 10-year frequency. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.	B2.1.44	Program will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
45	*High-Voltage Insulators* program	The *High-Voltage Insulators* program is a new condition monitoring program that visually inspects high voltage insulator surfaces and metallic parts at least once every two years initially with the frequency adjusted based on plant specific operating experience. For high-voltage insulators that are coated, the visual inspection will be performed at least once every five years. Industry and plant-specific operating experience will be evaluated in the development and implementation of this program.	B2.1.45	Program will be implemented 6 months prior to the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.
46	*Fatigue Monitoring* program	The *Fatigue Monitoring* program is an existing preventive program that will be enhanced as follows: 1. Procedures will be revised to require monitoring and tracking of transient cycles associated with the ASME Code, Section XI, Appendix L fatigue sensitive locations to be performed each inspection interval. Consistent with the existing cycle counting program, a surveillance limit will be established to initiate corrective actions prior to exceeding transient cycle assumptions in the ASME Code, Section XI, Appendix L analyses. 2. Procedures will be revised to expand existing corrective action guidance associated with exceeding a cycle counting surveillance limit to recommend consideration of component repair, component replacement, performance of a more rigorous analysis, performance of an ASME Code, Section XI, Appendix L flaw tolerance analysis, or scope expansion to consider other locations with the highest expected CUF_{en} values. 3. Procedures will be revised to require that when a cycle counting action limit is reached, action will be taken to ensure that the analytical bases of the High-Energy Line Break (HELB) locations are maintained.	B3.1	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
47	*Neutron Fluence Monitoring* program	The *Neutron Fluence Monitoring* program is an existing condition monitoring program that is credited.	B3.2	Ongoing
48	*Environmental Qualification of Electric Equipment* program	The *Environmental Qualification of Electric Equipment* program is an existing condition monitoring program that is credited.	B3.3	Ongoing

North Anna Power Station

Units 1 and 2

Application for Subsequent License Renewal

Appendix B
Aging Management Programs

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Appendix B

B1 Introduction

B1.1 Overview

Subsequent license renewal (SLR) Aging Management Program (AMP) descriptions are provided in this appendix for each program that has been credited for managing the effects of aging based upon the aging management review results provided in Sections 3.1 through 3.6

In general, there are four types of AMPs:

- Prevention programs preclude aging effects from occurring.
- Mitigation programs slow the effects of aging.
- Condition monitoring programs inspect/examine for the presence and extent of aging.
- Performance monitoring programs test the ability of a structure or component to perform its intended function.

More than one type of AMP may be implemented for a component 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 Appendix A.1, "Aging Management Review - Generic (Branch Technical Position RLSB-1)" and in Table A.1-1 "Elements of an Aging Management Program for Subsequent License Renewal" of NUREG-2192. The 10-element detail is not provided when the program is deemed to be consistent with the assumptions made in NUREG-2191. The 10-element detail is only provided when the program is plant-specific. There are no plant-specific AMPs in the North Anna Power Station (NAPS) Subsequent License Renewal Application (SLRA).

Existing initial license renewal aging management activities (AMAs) were used as a starting point for subsequent license renewal AMPs. Credit has been taken for other existing plant programs whenever an initial license renewal AMA did not exist. As such, existing programs and activities associated with a system, structure, component, or commodity grouping were reviewed to determine whether they include the necessary actions to adequately manage the effects of aging during the requested subsequent period of extended operation.

Existing plant programs were often based on a regulatory commitment or requirement, rather than aging management. Many of these existing programs required for initial license renewal included the 10-element attributes, and have been demonstrated to adequately manage the identified aging effects. If an existing program is not believed to adequately manage an identified aging effect during the subsequent period of extended operation, then the program will be enhanced as necessary as discussed further below. Occasionally, the creation of a new program has been deemed necessary for purposes of subsequent license renewal.

Included in Appendix A4, Table A4.0-1, Subsequent License Renewal Commitments, are commitments for SLR with the associated implementation schedule for when Dominion plans to complete each commitment.

B1.2 Method of Discussion

Each of the AMPs in Sections B2.1.1 through B3.3 are consistent with the assumptions in Sections X and XI of NUREG-2191, or are consistent with exceptions and/or enhancements, and contain the following:

- A Program Description summary of the overall program form and function.
- A NUREG-2191 Consistency statement about the program.
- A discussion of any exceptions to the NUREG-2191 program with a justification.
- A discussion of any enhancements or additions to ensure consistency with NUREG-2191 along with a proposed schedule for completion.
- Operating Experience information specific to the program.
- A Conclusion with a bases statement of reasonable assurance that the existing program is effective, or will be effective when implemented, if new or enhanced.

There are no plant-specific AMPs in the NAPS SLRA.

B1.3 Quality Assurance Program and Administrative Controls

The Quality Assurance (QA) Program is described in Topical Report DOM-QA-1, “Dominion Energy Nuclear Facility Quality Assurance Program Description,” which implements the requirements of 10 CFR 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.” The QA Program includes the three elements of Corrective Actions, Confirmation Process, and Administrative Controls, which are applicable to the safety-related and nonsafety-related systems, structures, and components (SSCs) that are subject to aging management review. The QA Program is consistent with NUREG-2191, Appendix A, “Quality Assurance for Aging Management Programs,” and the summary in NUREG-2192, Appendix A.2, “Quality Assurance for Aging Management Programs (Branch Technical Position IQMB-1).”

Generically the three elements are applicable as follows:

Corrective Actions:

Results that do not meet acceptance criteria are addressed as conditions adverse to quality or significant conditions adverse to quality under Section 16, “Corrective Action,” of the QA Program. The Corrective Action Program is implemented in accordance with the requirements of 10 CFR 50, Appendix B and Topical Report DOM-QA-1. A single program is used regardless of the safety classification of the structure or component.

Corrective actions are implemented through the initiation of a Condition Report (CR) for actual or potential problems, correction of an equipment deficiency, or the need for corrective maintenance, which drive initiation of a work order. The corrective action procedures specify steps for promptly reporting, evaluating, and correcting conditions adverse to quality and significant conditions adverse to quality commensurate with the significance of the SSC or activity. Consistent with the significance of the identified condition, these steps include: (1) deficiency identification, (2) deficiency review, impact on operations and reportability determination, (3) CR review, trending and classification (including extent of condition and extent of cause), (4) corrective action determinations, assignments, and implementation, (5) assessment of effectiveness of correction, and (6) CR closure.

In the case of significant conditions adverse to quality, measures are implemented to ensure that: (a) senior station management are notified; (b) cause is determined; (c) corrective action is taken to preclude repetition; (d) the cause and corrective actions are documented and reported to station management; and (e) corrective action is taken in a timely and accurate manner.

Confirmation Process:

The Dominion Corrective Action Program contains confirmation process measures for assuring that conditions adverse to quality are promptly identified and corrected. The program stresses that verification of implementation and close-out of corrective action documentation take place and contains measures to monitor these activities by facility and oversight personnel. Plant procedures include provisions for timely evaluation of adverse conditions and implementation of corrective actions required, including Root Cause Evaluations and prevention of repetition where appropriate (e.g.; significant conditions adverse to quality). These procedures provide for tracking, coordinating, monitoring, reviewing, verifying, validating and approving corrective actions, and ensure that corrective actions have been effectively implemented. The corrective action process is also monitored for potentially adverse trends. Identification of a potentially adverse trend due to recurring or repetitive unacceptable conditions will result in the initiation of a CR. Since the same 10 CFR 50, Appendix B corrective actions and confirmation process are applied for nonconforming safety-related and nonsafety-related structures and components subject to aging management review for subsequent license renewal, the confirmation process is consistent with the NUREG-2191 elements.

Administrative Controls:

Information on the organizational structure, responsibilities, authorities, and personnel qualification requirements is provided in the Updated Final Safety Analysis Report (UFSAR) and in the QA Program. The organizational structure, responsibilities, authorities, and personnel qualification requirements conform to 10 CFR 50, Appendix B. The QA Program provides orderly and uniform administrative and managerial controls for safe operation of its nuclear stations. Administrative controls apply to applicable activities, documents, procedures, and instructions regardless of the safety classification of the associated system, structure, component, or commodity group. Document control processes are implemented in accordance with the requirements of 10 CFR 50, Appendix B, and implementation is further clarified in the QA Program. Measures are provided to assure that documents, including revisions or changes, are properly reviewed by independent personnel, approved, and distributed prior to use; this includes those for the activities performed under the programs credited for aging management. Administrative controls also provide for formal review and approval of corrective actions. The administrative controls apply to both safety-related and nonsafety-related structures, systems, and components (SSCs) which are subject to aging management.

B1.4 Operating Experience

Operating experience from internal (also referred to as “plant-specific”) and external (also referred to as “industry”) sources is captured and systematically reviewed on an ongoing basis in accordance with the QA Program, which meets the requirements of 10 CFR 50, Appendix B, and with the Operating Experience (OE) Program, which meets the requirements of NUREG-0737, “Clarification of TMI Action Plan Requirements,” Item I.C.5, “Procedures for Feedback of Operating Experience to Plant Staff.” The Dominion OE Program interfaces with, and relies on, active participation in the INPO OE program, as endorsed by the NRC.

OE is used to enhance plant programs, prevent repeat events, and prevent events that are similar to those that have occurred at other plants. Personnel receive OE (internal and external) daily. The OE process includes screening, evaluation, and acting on operating experience documents and information to prevent or mitigate the consequences of similar events. External OE includes INPO documents, NRC documents (e.g., NUREG-2191 revisions, Information Notices, Regulatory Issues Summaries, and license renewal Interim Staff Guidance documents), and other industry documents (e.g., Licensee Event Reports and 10 CFR Part 21 reports, as well as relevant research and development information). Internal OE includes relevant items from the Corrective Action Program. Program health reports and program assessments are also reviewed by program owners, as applicable.

The systematic review of plant-specific and industry OE concerning aging management and age-related degradation ensures that the license renewal AMPs are, and will continue to be, effective in managing the aging effects for which they are credited. OE involving age-related degradation is tracked and trended such that adverse trends are entered into the Corrective Action Program for evaluation. Potential aging issues associated with SSCs within the scope of license renewal are evaluated with regard to: (a) materials of construction, (b) operating environment, (c) aging effects, (d) aging mechanisms, and (e) AMPs, to determine if changes to AMPs or new AMPs are needed. Existing AMPs are enhanced, or new AMPs are developed, when it is determined through the evaluation of OE that the effects of aging may not be adequately managed. Aging management programs are informed by the review of OE on an ongoing basis, regardless of the AMPs implementation schedule. Guidelines have been established for reporting plant-specific OE regarding age-related degradation and aging management to the industry through the INPO Consolidated Event System (ICES), consistent with the guidance in NEI 14-13, “Use of Industry Operating Experience for Age-Related Degradation and Aging Management Programs.” In addition, as further discussed below, the Dominion process requires the periodic conduct of AMP effectiveness reviews, such that they are performed within a five-year period and are performed consistent with the guidance of NEI 14-12, “Aging Management Program Effectiveness.” The objective of reporting OE is to provide useful information to the industry in a timely manner and, therefore, support the prevention of similar events and the detection of adverse and emerging trends.

Training on age-related degradation and aging management is provided to those personnel responsible for implementing the AMPs and those personnel who may submit, screen, assign, evaluate, or otherwise process plant-specific and industry OE. The scope of training is linked to the responsibilities for processing OE. This training occurs on a periodic basis and includes provisions to accommodate the turnover of plant personnel.

Each AMP summary in this appendix contains examples of OE relevant to the program. This information is obtained through the review of plant-specific OE captured by the Corrective Action Program, program assessments, and program health reports, as well as the review of industry OE. New programs utilized plant-specific and/or industry OE, as applicable, and the AMP summaries in this appendix discuss the OE and associated corrective actions as they relate to implementing the new program. The OE summary for each AMP in this appendix identifies past corrective actions which 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 program will be adequately maintained during the subsequent period of extended operation.

License Renewal Aging Management Program Effectiveness and Oversight

Consistent with the guidance in Section 6 of Appendix B of NEI 17-01, "Industry Guideline for Implementing the Requirements of 10 CFR 54 for Subsequent License Renewal," effectiveness reviews of initial license renewal aging management activities were performed, and are presented within the SLRA Appendix B AMP sub-sections that are most related to those initial license renewal aging management activities (AMAs). For example, there were several initial license renewal AMAs related to water chemistry control. An assessment of the effectiveness of the water chemistry control AMAs (UFSAR Section 18.2.4 and Section 18.2.5) is presented within SLRA Section B2.1.2, which describes the subsequent license renewal Water Chemistry AMP. The initial license renewal AMAs are being actively managed during the current period of extended operation but confirmation of the effective implementation of these AMAs continues to be pursued and areas for further improvement identified that will heighten the effectiveness of aging management both now and during the subsequent period of extended operation.

Effectiveness reviews of the initial license renewal AMAs were performed, consistent with NEI 14-12, Revision 0, "Aging Management Program Effectiveness," to identify gaps. In addition, the following oversight activities have identified gaps and associated corrective actions that have been implemented to improve the effectiveness of the initial license renewal AMAs.

1. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. Reviews were conducted to verify that open commitments were on-track to be completed prior to the projected NRC Phase 2 inspection date and that closed commitments had not been adversely impacted by changes to the facility, programs or documents. The scope of the Unit 1 refueling outage 25 schedule was reviewed to verify that implementation or planned implementation of aging management activities met their intent as described within licensing basis documents. An overall conclusion was reached that adequate progress had been made in commitment closure and inspection readiness. However, performance deficiencies and learning opportunities were identified to address various gaps associated with the following initial license renewal AMAs:
    - Buried Piping and Valve Inspection Activities (UFSAR Section 18.1.1)
    - Infrequently Accessed Area Inspection Activities (UFSAR Section 18.1.2)
    - Work Control Process (UFSAR Section 18.2.19)
    - Civil Engineering Structural Inspection (UFSAR Section 18.2.6)
    - General Condition Monitoring Activities (UFSAR Section 18.2.9)
    - Inservice Inspection (ISI) Program - Component and Component Support Inspections (UFSAR Section 18.2.11)

- Tank Inspection Activities (UFSAR Section 18.1.3)

Since gaps in the above AMAs have the potential to impact descriptions of AMPs in the SLRA, associated issues are discussed in the following Appendix B sections when warranted:

- Buried and Underground Piping and Tanks (Section B2.1.27)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section B2.1.25)
- Structures Monitoring (Section B2.1.34)
- External Surfaces Monitoring of Mechanical Components (Section B2.1.23)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section B2.1.1)
- Outdoor and Large Atmospheric Metallic Storage Tanks (Section B2.1.17)

On September 22, 2016, the NRC completed an IP 71003 Phase I inspection of NAPS Unit 1. The resulting inspection report concluded that based on the sample selected for review, the inspectors determined that commitments, license conditions, and regulatory requirements associated with the renewed facility operating license were either being met; or where commitment actions had not been completed, that the licensee had administrative controls in place to ensure completion before the period of extended operation.

2. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

3. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted from November through December of 2017. Reviews were conducted to verify that commitment closure documentation, AMAs, and implementation documents were complete and met IP 71003 expectations. No missed inspections or commitments were identified. However, areas for improvement and enhancements were identified to address various gaps associated with the following initial license renewal AMAs:

   - Infrequently Accessed Area Inspection Activities (UFSAR Section 18.1.2)

- Tank Inspection Activities (UFSAR Section 18.1.3)
- Augmented Inspection Activities (UFSAR Section 18.2.1)
- Work Control Process (UFSAR Section 18.2.19)
- Non-EQ Cable Monitoring (UFSAR Section 18.1.4)

Since gaps in the above AMAs have the potential to impact descriptions of AMPs in the SLRA, associated issues are discussed in the following Appendix B sections when warranted:

- Outdoor and Large Atmospheric Metallic Storage Tanks (Section B2.1.17)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section B2.1.1)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section B2.1.25)
- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B2.1.37)
- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (Section B2.1.38)
- Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B2.1.39)

On December 15, 2017, the NRC completed an IP 71003 Phase II inspection of North Anna Power Station Units 1 and 2. The resulting inspection report concluded that no findings or violations of greater than minor significance were identified. On the basis of the sample selected for review, the NRC team determined that the licensee had completed, or was on track to complete, the necessary tasks to meet the license renewal commitments, license conditions, and regulatory requirements associated with the issuance of the renewed operating licenses for Units 1 and 2. Based on the review of program documents and activities completed at the time of this inspection, the team determined that the licensee had established the required AMAs and TLAAs to manage the aging effects of in-scope structures, systems, and components through the period of extended operation of the two units.

4. In April 2019, effectiveness reviews were performed on the initial license renewal AMAs. The AMAs were evaluated against performance criteria identified in NEI 14-12 that were adapted for the effectiveness reviews and summarized as follows:

   - Implementing procedures contain acceptance criteria for each parameter monitored or inspected.
   - Acceptance criteria anticipate rates of change and margin to loss of function.
   - Inspections and examinations are conducted at appropriate intervals.

- Operating experience is considered in evaluating the appropriateness of technique and frequency and adoption of new techniques as they become available.
- Industry operating experience and plant operating experience, including corrective actions, are used to inform AMAs.
- There are no significant findings from the NRC, industry peers, or from internal sources against the program.
- Implementing procedures are consistent with license renewal commitments.

The AMAs were also evaluated against performance criteria identified as a result of a Nuclear oversight audit on License Renewal at Surry Power Station that were adapted for the North Anna Power Station effectiveness reviews and summarized as follows:

- Implementing activities are completed as scheduled and not deferred without adequate technical justification.
- Corrective actions, including repairs, causal evaluation and prevention of recurrence, are timely.
- Corrective actions apply appropriate extent of condition.

No gaps were identified with 20 of the 24 initial license renewal AMAs. Gaps were identified with the Non-EQ Cable Monitoring AMA (UFSAR Section 18.1.4), Fire Protection Program AMA (UFSAR Section 18.2.7), Reactor Vessel Integrity Management AMA (UFSAR Section 18.2.14), and Work Control Process AMA (UFSAR Section 18.2.19). The gaps were documented in the Corrective Action Program and corrective actions were initiated. The effectiveness reviews are addressed in the operating experience summary of the applicable Appendix B AMPs.

B1.5 NUREG-2191 AMP Correlation

The correlation between NUREG-2191, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report," programs and the programs that have been credited for managing the effects of aging in the SLRA are shown in Table B1-1. For the programs, links to the sections that include the program descriptions are provided.

Table B1-1
Correlation: NUREG-2191 Program with NAPS Program

NUREG-2191 Number	NUREG-2191 Program	North Anna Power Station Program	Appendix B Reference
XI.M1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	B2.1.1
XI.M2	Water Chemistry (Primary and Secondary)	Water Chemistry (Primary and Secondary)	B2.1.2
XI.M3	Reactor Head Closure Stud Bolting (addressed by ISI program)	Reactor Head Closure Stud Bolting (addressed by ISI program)	B2.1.3
XI.M4	BWR Vessel ID Attachment Welds	Not Applicable to a PWR	N/A
XI.M7	BWR Stress Corrosion Cracking	Not Applicable to a PWR	N/A
XI.M8	BWR Penetrations	Not Applicable to a PWR	N/A
XI.M9	BWR Vessel Internals	Not Applicable to a PWR	N/A
XI.M10	Boric Acid Corrosion	Boric Acid Corrosion	B2.1.4
XI.M11B	Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components	Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components	B2.1.5
XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	B2.1.6
XI.M16A	PWR Vessel Internals	PWR Vessel Internals	B2.1.7
XI.M17	Flow-Accelerated Corrosion	Flow-Accelerated Corrosion	B2.1.8

Table B1-1
Correlation: NUREG-2191 Program with NAPS Program

NUREG-2191 Number	NUREG-2191 Program	North Anna Power Station Program	Appendix B Reference
XI.M18	Bolting Integrity	Bolting Integrity	B2.1.9
XI.M19	Steam Generators	Steam Generators	B2.1.10
XI.M20	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System	B2.1.11
XI.M21A	Closed Treated Water Systems	Closed Treated Water Systems	B2.1.12
XI.M22	Boraflex Monitoring	Not applicable. This material is not used in the NAPS spent fuel pool racks	N/A
XI.M23	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	B2.1.13
XI.M24	Compressed Air Monitoring	Compressed Air Monitoring	B2.1.14
XI.M25	BWR Reactor Water Cleanup System	Not Applicable to a PWR	N/A
XI.M26	Fire Protection	Fire Protection	B2.1.15
XI.M27	Fire Water System	Fire Water System	B2.1.16
XI.M29	Outdoor and Large Atmospheric Metallic Storage Tanks	Outdoor and Large Atmospheric Metallic Storage Tanks	B2.1.17
XI.M30	Fuel Oil Chemistry	Fuel Oil Chemistry	B2.1.18
XI.M31	Reactor Vessel Material Surveillance	Reactor Vessel Material Surveillance	B2.1.19
XI.M32	One-Time Inspection	One-Time Inspection	B2.1.20
XI.M33	Selective Leaching	Selective Leaching	B2.1.21
XI.M35	ASME Code Class 1 Small-Bore Piping	ASME Code Class 1 Small-Bore Piping	B2.1.22
XI.M36	External Surfaces Monitoring of Mechanical Components	External Surfaces Monitoring of Mechanical Components	B2.1.23

Table B1-1
Correlation: NUREG-2191 Program with NAPS Program

NUREG-2191 Number	NUREG-2191 Program	North Anna Power Station Program	Appendix B Reference
XI.M37	Flux Thimble Tube Inspection	Flux Thimble Tube Inspection	B2.1.24
XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	B2.1.25
XI.M39	Lubricating Oil Analysis	Lubricating Oil Analysis	B2.1.26
XI.M40	Monitoring of Neutron-Absorbing Materials Other Than Boraflex	Not Applicable. NAPS spent fuel storage racks do not include any neutron absorbing materials	N/A
XI.M41	Buried and Underground Piping and Tanks	Buried and Underground Piping and Tanks	B2.1.27
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	B2.1.28
XI.S1	ASME Section XI, Subsection IWE	ASME Section XI, Subsection IWE	B2.1.29
XI.S2	ASME Section XI, Subsection IWL	ASME Section XI, Subsection IWL	B2.1.30
XI.S3	ASME Section XI, Subsection IWF	ASME Section XI, Subsection IWF	B2.1.31
XI.S4	10 CFR Part 50, Appendix J	10 CFR Part 50, Appendix J	B2.1.32
XI.S5	Masonry Walls	Masonry Walls	B2.1.33
XI.S6	Structures Monitoring	Structures Monitoring	B2.1.34
XI.S7	Inspection of Water-Control Structures Associated with Nuclear Power Plants	Inspection of Water-Control Structures Associated with Nuclear Power Plants	B2.1.35
XI.S8	Protective Coating Monitoring and Maintenance	Protective Coating Monitoring and Maintenance	B2.1.36

Table B1-1
Correlation: NUREG-2191 Program with NAPS Program

NUREG-2191 Number	NUREG-2191 Program	North Anna Power Station Program	Appendix B Reference
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	B2.1.37
XI.E2	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	B2.1.38
XI.E3A	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.39
XI.E3B	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.40
XI.E3C	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.41
XI.E4	Metal-Enclosed Bus	Metal-Enclosed Bus	B2.1.42
XI.E5	Fuse Holders	Fuse Holders	B2.1.43
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	B2.1.44
XI.E7	High-Voltage Insulators	High-Voltage Insulators	B2.1.45
X.M1	Fatigue Monitoring	Fatigue Monitoring	B3.1
X.M2	Neutron Fluence Monitoring	Neutron Fluence Monitoring	B3.2

Table B1-1
Correlation: NUREG-2191 Program with NAPS Program

NUREG-2191 Number	NUREG-2191 Program	North Anna Power Station Program	Appendix B Reference
X.E1	Environmental Qualification of Electric Equipment	Environmental Qualification of Electric Equipment	B3.3
X.S1	Concrete Containment Unbonded Tendon Prestress	Not applicable. NAPS Containments do not have post tensioned tendon groups.	N/A

B1.6 Time-Limited Aging Analysis Programs

The following time-limited aging analysis aging management programs are described in the sections listed in this appendix. These programs are discussed in NUREG-2191.

- Fatigue Monitoring (Section B3.1)
- Neutron Fluence Monitoring (Section B3.2)
- Environmental Qualification of Electric Equipment (Section B3.3)

B2 Aging Management Programs

Table B2-1 lists the aging management programs described in this appendix and identifies the programs consistency with NUREG-2191. As discussed in Section B1.4, both plant specific and industry operating experience has been reviewed and considered as it relates to both new and existing aging management programs.

Table B2-1
NAPS Program Consistency with NUREG-2191 Program

NUREG-2191 Program	Appendix B Reference	Existing or New	Program has NUREG-2191 Enhancements	Program has Exceptions to NUREG-2191
ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	B2.1.1	Existing	X	
Water Chemistry (Primary and Secondary)	B2.1.2	Existing		
Reactor Head Closure Stud Bolting (addressed by ISI program)	B2.1.3	Existing		X
Boric Acid Corrosion	B2.1.4	Existing		
Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-induced Corrosion in Reactor Coolant Pressure Boundary Components	B2.1.5	Existing		
Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	B2.1.6	Existing		
PWR Vessel Internals	B2.1.7	Existing	X	
Flow-Accelerated Corrosion	B2.1.8	Existing	X	
Bolting Integrity	B2.1.9	Existing	X	
Steam Generators	B2.1.10	Existing		
Open-Cycle Cooling Water System	B2.1.11	Existing		X
Closed Treated Water Systems	B2.1.12	Existing	X	

Table B2-1
NAPS Program Consistency with NUREG-2191 Program

NUREG-2191 Program	Appendix B Reference	Existing or New	Program has NUREG-2191 Enhancements	Program has Exceptions to NUREG-2191
Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	B2.1.13	Existing		
Compressed Air Monitoring	B2.1.14	Existing		
Fire Protection	B2.1.15	Existing	X	
Fire Water System	B2.1.16	Existing	X	X
Outdoor and Large Atmospheric Metallic Storage Tanks	B2.1.17	Existing	X	X
Fuel Oil Chemistry	B2.1.18	Existing	X	X
Reactor Vessel Material Surveillance	B2.1.19	Existing		
One-Time Inspection	B2.1.20	New		
Selective Leaching	B2.1.21	New		
ASME Code Class 1 Small-Bore Piping	B2.1.22	New		
External Surfaces Monitoring of Mechanical Components	B2.1.23	Existing	X	
Flux Thimble Tube Inspection	B2.1.24	Existing		
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	B2.1.25	Existing	X	
Lubricating Oil Analysis	B2.1.26	Existing		
Buried and Underground Piping and Tanks	B2.1.27	Existing	X	
Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	B2.1.28	Existing	X	X
ASME Section XI, Subsection IWE	B2.1.29	Existing	X	

Table B2-1
NAPS Program Consistency with NUREG-2191 Program

NUREG-2191 Program	Appendix B Reference	Existing or New	Program has NUREG-2191 Enhancements	Program has Exceptions to NUREG-2191
ASME Section XI, Subsection IWL	B2.1.30	Existing		
ASME Section XI, Subsection IWF	B2.1.31	Existing	X	
10 CFR Part 50, Appendix J	B2.1.32	Existing		
Masonry Walls	B2.1.33	Existing		
Structures Monitoring	B2.1.34	Existing	X	
Inspection of Water-Control Structures Associated with Nuclear Power Plants	B2.1.35	Existing	X	
Protective Coating Monitoring and Maintenance	B2.1.36	Existing		
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.37	Existing	X	
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	B2.1.38	Existing	X	
Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.39	Existing	X	
Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.40	New		

Table B2-1
NAPS Program Consistency with NUREG-2191 Program

NUREG-2191 Program	Appendix B Reference	Existing or New	Program has NUREG-2191 Enhancements	Program has Exceptions to NUREG-2191
Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.41	New		
Metal-Enclosed Bus	B2.1.42	Existing	X	
Fuse Holders	B2.1.43	Existing		
Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.44	New		
High-Voltage Insulators	B2.1.45	New		
Fatigue Monitoring	B3.1	Existing	X	
Neutron Fluence Monitoring	B3.2	Existing		
Environmental Qualification of Electric Equipment	B3.3	Existing		

B2.1 Aging Management Program Details

B2.1.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

Program Description

The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program is an existing condition monitoring program that manages cracking, loss of fracture toughness, and loss of material. The program consists of periodic volumetric, surface, and/or visual examination, and leakage tests of the ASME Code, Section XI Class 1, 2, and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting for assessment, identification of signs of degradation, and establishment of corrective actions.

The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* aging management program implements the required component examination schedule in accordance with ASME Code Section XI, Subsection IWB-2400, IWC-2400 or IWD-2400 and examination categories, applicable components, examination methods, acceptance standards, and frequency of examination as specified in ASME Code, Section XI Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1 for Class 1, 2, and 3 components, respectively. The examination methods specified in ASME Code, Section XI, Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1 are based on approved industry standards for detecting age-related degradation of components. The program requires that indications and relevant conditions detected during examinations be evaluated in accordance with ASME Code, Section XI, Articles IWB-3000 for Class 1, IWC-3000 for Class 2, and IWD-3000 for Class 3. The program directs that repair and replacement activities be performed in accordance with ASME Code, Section XI, Subsection IWA-4000.

Additional examinations not required by the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program, but using ASME Code, Section XI inspection techniques and acceptance criteria, are performed in accordance with the Augmented Inspection program.

During the fifth inservice inspection interval (May 1, 2019 through April 30, 2029) for Unit 1 and the fourth inspection interval (December 14, 2010 through December 13, 2020) for Unit 2, inservice inspections are performed consistent with the 2013 and 2004 editions, respectively, of ASME Code, Section XI, as approved in 10 CFR 50.55a. In conformance with 10 CFR 50.55a(g)(4)(ii), the inservice inspection program is updated during each successive 120-month inspection interval to comply with the requirements of the edition of the Code that is applicable twelve months before the start of the inspection interval. ASME Code editions and addenda will be used consistent with the provisions of 10 CFR 50.55a during the subsequent period of extended operation. Any deviation from ASME Code, Section XI requirements must be approved by the NRC per a relief request or alternate request.

A Risk-Informed Inservice Inspection (RI-ISI) program has been implemented using ASME Code, Section XI, Code Case N-716-1 “Alternative Classification and Examination Requirements, Section XI, Division 1". This methodology includes Class 1 piping welds and Class 2 components (excluding attachment welds and supports). The RI-ISI program has been incorporated into the ISI Schedule.

A flaw tolerance evaluation was performed for welds associated with sentinel locations assessed under ASME Code, Section XI, Appendix L. The sentinel locations to be examined periodically include auxiliary lines for the following:

- Safety injection (6-inch diameter RCS cold leg nozzle)
- Surge (14-inch hot leg surge nozzle; nozzle-to-pipe weld)

Fatigue monitoring will include periodic examinations of the pressurizer spray nozzle stainless steel-to-safe-end weld.

The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program includes the component inspection activities required by ASME Code, Section XI, Subsections IWB, IWC, and IWD, except for those components that are covered by the following subsequent license renewal aging management programs that include augmented requirements:

- *Reactor Head Closure Stud Bolting* program (B2.1.3)
- *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program (B2.1.5)
- *PWR Vessel Internals* program (B2.1.7)
- *Bolting Integrity* program (B2.1.9)
- *Steam Generators* program (B2.1.10)
- *ASME Code Class 1 Small-Bore Piping* program (B2.1.22)
- *Flux Thimble Tube Inspection* program (B2.1.24)
- *ASME Section XI, Subsection IWF* program (B2.1.31)
- *Fatigue Monitoring* program (B3.1)

Additional examinations associated with the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program are identified in the Augmented Inspection program, and are included in the ISI Schedule, for the following components:

- Pressurizer Safety Valve Inlet Lines
- Thermal Sleeves
- Reactor Vessel Core Barrel Holddown Spring
- Reactor Vessel Radial Supports
- Main Steam Postulated Break Locations
- Feedwater Postulated Break Locations
- Steam Generator Feedwater Nozzles
- Pressurizer Surge Line
- MRP-146 Thermal Fatigue
- MRP-227-A Reactor Vessel Internals Inspections

Three other aspects of the Augmented Inspections are included in non-ISI programs. Inspections of reactor vessel incore detector thimble tubes are described in the *Flux Thimble Tube Inspection* program (B2.1.24). Inspections of the reactor vessel head are described in the *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program (B2.1.5). Inspections of the PWR vessel internals are described in the *PWR Vessel Internals* program (B2.1.7).

The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program is an existing program that, following enhancement, will be consistent, with NUREG-2191, Section XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element:

Scope of Program (Element 1) and Detection of Aging Effects (Element 4)

1. Procedures will be revised to require inspections be performed for the following:
   a. Welds associated with sentinel locations assessed under ASME Code, Section XI, Appendix L include the safety injection 6-inch diameter RCS cold leg nozzles. One safety injection cold leg nozzle is to be inspected once per 10 years for either Unit 1 or Unit 2.
   b. The pressurizer spray nozzle stainless steel-to-safe-end weld is to be inspected once per 10 years for each unit.
2. Procedures will be revised to require periodic volumetric inspections of the steam generator feedwater nozzle thermal sleeves.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In September 2009, it was discovered that three components (restricting orifice) in the charging system were not listed as bolted connections requiring inspection for the ISI program. There was no evidence that the three components were inspected per ASME Code, Section XI requirements in the previous ISI interval. Inspections of the three components were completed in Fall 2009. Drawing updates were processed to properly label the components for both units for inclusion in the ISI Program Plan.
2. In March 2010, three rejectable weld indications were identified during an ASME Code, Section XI examination of piping in the recirculation spray system. A repair/replacement plan was prepared, and weld repairs were completed.
3. In March 2013, EPRI Material Reliability Program (MRP) issued Good Practices per NEI 03-08 as documented in MRP-192, “Assessment of Residual Heat Removal Mixing Tee Thermal Fatigue in PWR Plants,” Revision 2. ISI documents were reviewed for compliance with and to capture recommendations from MRP-192, Revision 2. The inspection guidance for the mixing tee welds has been updated with the examination volume details from MRP-192, Revision 2, in case future examinations are performed.

4. In December 2014, a steam leak was observed on the ‘B’ RCS intermediate loop. The degraded condition was a through-wall leak on the loop drain line elbow due to thermal fatigue failure. A Root Cause Evaluation was performed and corrective actions included replacing the leaking elbow, performing examinations at other susceptible drain line locations, replacing loop drain line components having relevant indications, revising examination programs to include more frequent examinations for susceptible locations, and reviewing sources of thermal stresses to adjust examination frequency as required.
5. In September 2015, a leak was discovered on a service water pipe (ASME Code, Section XI, Class 3). The cause of the leak was determined to be microbiologically influenced corrosion. The leak repair involved installation of a new section of stainless steel pipe using three welds.
6. In May 2016, an assessment was performed to determine the progress and substance of license renewal commitment closure and readiness for the IP71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. Commitment 11 indicated that the licensee would follow industry activities related to failure mechanisms for small-bore piping, and evaluate changes to inspection activities based on industry recommendations. An action item resulting from the industry recommendations was created to develop an Engineering evaluation to include additional guidance for inspections of small-bore piping. The Engineering evaluation was completed in September 2017. That action completed the development of inspection plans for small-bore piping to close Commitment 11. No other performance deficiencies or learning opportunities were identified for the Inservice Inspection (ISI) Program – Component and Component Support Inspections AMA (UFSAR Section 18.2.11), the Augmented Inspection Activities AMA (UFSAR Section 18.2.1), and the ISI Program - Reactor Vessel AMA (UFSAR Section 18.2.13).
7. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.
8. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. With the exception of the inspection of the pressurizer surge line welds (Commitment 24) no follow-up actions were

identified for the Inservice Inspection (ISI) Program – Component and Component Support Inspections AMA (UFSAR Section 18.2.11), the Augmented Inspection Activities AMA (UFSAR Section 18.2.1), and the ISI Program - Reactor Vessel AMA (UFSAR Section 18.2.13). Commitment 24 required that an inspection plan be submitted to the NRC regarding the Augmented Inspection Activities AMA for the pressurizer surge line. The NRC report for the results from the Phase I IP 71003 inspection (ML16306A189; October 31, 2016) indicated that the inspectors verified that although the surge line inspections were not completed at the time of the inspection, the plan was in place to complete the surge line inspections prior to the PEO. Commitment 24 was determined to be completed at the time of the Phase II IP 71003 inspection (ML18029A029, January 26, 2018).

9. In February 2018, an assessment of the Dominion Fleet ISI program was performed to determine compliance with ASME Code, Section XI Code requirements, Dominion commitments, and industry risk-informed applications. The Dominion Fleet ISI program was determined to be effective and fully implemented for compliance with ASME Code, Section XI.
10. In April 2019, an effectiveness review was performed for the Inservice Inspection (ISI) Program – Component and Component Support Inspections AMA (UFSAR Section 18.2.11), the Augmented Inspection Activities AMA (UFSAR Section 18.2.1), and the ISI Program - Reactor Vessel AMA (UFSAR Section 18.2.13). The AMAs were evaluated against the performance criteria identified in NEI 14-12, "Aging Management Program Effectiveness," for selected elements. No gaps were identified by this effectiveness review.
11. In June 2020, data was collected for the period 2001 through 2019 for examinations of reactor coolant pump (RCP) motor flywheels. At intervals of approximately 10 years or less, non-destructive examinations (NDE) had been performed to evaluate the condition of the RCP motor flywheels. The NDE included combinations of ultrasonic testing, magnetic particle testing, and liquid penetrant testing. The NDE did not identify any recordable indications.

The above examples of operating experience provide objective evidence that the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program includes activities to perform periodic volumetric, surface, and/or visual examinations, and leakage tests to identify cracking, loss of fracture toughness, and loss of material for the ASME Code, Section XI Class 1, 2, and 3 pressure-retaining components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *ASME*

Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.2 Water Chemistry

Program Description

The *Water Chemistry* program is an existing preventive program that manages cracking, loss of material, reduction of heat transfer, and wall thinning of components exposed to a reactor coolant, steam, treated borated water, and treated water environment. The scope of the Primary Water Chemistry program includes monitoring and control of the chemical environment in the reactor coolant system and related pressurized water reactor (PWR) interfacing systems. The scope of the Secondary Water Chemistry program includes monitoring and control of the chemical environment in the steam generator secondary side and the secondary cycle systems. The Primary Water Chemistry program is consistent with EPRI Report 3002000505, “Pressurized Water Reactor Primary Water Chemistry Guidelines,” Revision 7. The Secondary Water Chemistry program is consistent with EPRI Report 3002010645, “Pressurized Water Reactor Secondary Water Chemistry Guidelines,” Revision 8.

The primary and secondary water chemistry control strategies are set forth in strategic plans and implemented by procedures. The programmatic control of the chemical environment ensures that the aging effects due to contaminants are limited. The methods used to manage both the primary and secondary chemical environments rely on the principles of: (1) limiting the concentration of chemical species known to cause corrosion and (2) addition of chemical species known to inhibit material degradation by their influence on pH and dissolved oxygen levels.

The primary portion of the program is consistent with EPRI Report 3002000505 and includes specific limits for pH, lithium, fluoride, chloride, sulfate, dissolved oxygen, and other parameters. Zinc injection is used for source term reduction in the primary systems. Control of reactor coolant and related interfacing system contaminants is maintained by using micron and submicron filters and mixed bed demineralizers, which provide mechanical filtration and ion exchange functions to remove contaminants. Lithium hydroxide addition is used to control reactor coolant pH, while hydrogen addition is utilized for oxygen scavenging.

The secondary portion of the program is consistent with EPRI Report 3002010645 and includes specific limits for chloride, sulfate, sodium, hydrazine, dissolved oxygen, total iron, pH, conductivity, and other parameters. Chemical control of the secondary systems is established and maintained by removing contaminants with steam generator blowdown combined with condensate demineralizers during startup and mechanical filtration during power operations. Chemical addition of approved amines (e.g., ethanolamine-ETA), is utilized for pH control. Hydrazine is used to scavenge oxygen in secondary systems.

Water chemistry control is generally effective in areas of intermediate and high flow where mixing takes place and the monitoring samples are representative of actual conditions. For low-flow areas and stagnant portions of the systems, sampling may not be as effective in determining local chemical environment conditions. A one-time inspection prior to the period of subsequent license renewal of a representative group of components will provide verification of the effectiveness of the *Water Chemistry* program in these low-flow areas. This inspection will be performed as part of the *One-Time Inspection* program (B2.1.20) for the verification of the effectiveness of the *Water Chemistry* program.

The *Water Chemistry* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *Water Chemistry* program is an existing program that is consistent with NUREG-2191, Section XI.M2, Water Chemistry as modified by SLR-ISG-Mechanical-2020-XX, Updated Aging Management Criteria for Mechanical Portions of the Subsequent License Renewal Guidance.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Water Chemistry* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In October 2008 during startup of Unit 2, a reactor coolant system sample indicated that the hydrogen concentration was out of specification high. A condition report was written, the volume control tank was vented, and pressure was maintained less than 30 psi to allow the hydrogen concentration in the reactor coolant system to decrease. The monitoring frequency was increased to assess the concentration trend. Hydrogen concentration returned to specification in approximately 10 hours.

   Two additional hydrogen excursions occurred over a two week period and were returned to specification after corrective actions. A condition report was written and an apparent cause evaluation was conducted to investigate the causes.

The apparent cause was determined to be inadequate written instructions and communication. Chemistry personnel made decisions regarding the control of hydrogen concentration based on individual knowledge and skills. No calculation program existed to project hydrogen concentration under varying plant conditions.

To correct the issue, a calculation was developed to predict reactor coolant system hydrogen concentration during unit startup. The calculation was incorporated into the startup procedure. Since the calculation was incorporated, there have been no further occurrences of hydrogen concentration going out of specification during startup.

2. In April 2009 during the startup of Unit 1, several secondary samples indicated that iron concentration was greater than 5 ppb. Chemistry performance metrics are negatively impacted if iron concentration is greater than 5 ppb when the unit is above 30 percent power. The sample collected from 30-50 percent power indicated 13 ppb iron. The sample collected from 50-90 percent power indicated 8 ppb iron. While these values did not exceed procedural limits, improvement was deemed necessary.

   Samples from the feedwater, high pressure heater drain, and condensate systems were collected from each unit at different power levels as part of an action plan to reduce iron transport. Sampling data showed that the highest iron transport to the feedwater system occurs from 30-50 percent power, and originates from the high pressure heater drain system.

   To correct the issue, procedures were revised to direct more thorough flushing of stagnant condensate and feedwater piping upon startup of the condensate system. Emphasis was also added to initiate blowdown to clean up the feedwater sources prior to entry into the steam generators. Additionally, guidance was provided to flush the high pressure heater drain tanks upon startup. Following the incorporation of these actions, feedwater iron values have consistently been below 5 ppb with no impact to performance metrics during startups.

3. In February 2011, a primary sample was taken and analyzed prior to scheduled testing that would decrease ventilation flow in the primary sample room sample sink. Primary sampling is normally performed approximately every 24 hours. Station personnel elected to wait until after the testing was concluded to perform another primary sample. When the testing was completed approximately 36 hours after the initial sample, a sample was taken. Results of the sample indicated that lithium concentration had decreased below a procedure lower limit. A verification sample corroborated the results. The cation resin bed was removed from service, and lithium returned to specification.

   An apparent cause evaluation was conducted to investigate the causes. Results of the evaluation determined that the potential risks of the change in sampling schedule were not adequately evaluated. To correct the issue, a chemistry procedure revision was made to include a section detailing change management requirements if changes are made to chemistry policies and practices.

Additionally, it was determined that Chemistry personnel did not expect that lithium may go out of specification during the testing evolution. To correct the issue, procedural guidance was instituted to ensure that the trend for a parameter will be evaluated and documented in the chemistry logs any time an analysis will be not be completed as normally scheduled.

4. In May 2013 during a Unit 2 forced outage for turbine repairs, sulfate concentrations in the steam generators were elevated but below established action levels. Sulfate cleanup was slower than anticipated during the subsequent restart and power ascension.

   Primary temperature was maintained at approximately 360°F for 12 days while the turbine repairs were performed. Steam generator blowdown samples during that period indicated sulfate concentrations were increasing. This was due to desorption of sulfate from the internal surfaces of the steam generators (hideout return) at the elevated steam generator temperatures.

   During heatup and power ascension, sulfate cleanup via blowdown was slower than anticipated. Sources of potential sulfate introduction were analyzed and no external source was identified. The slow cleanup was attributed to the elevated pH in the steam generators causing the desorption of sulfate to accelerate.

   Blowdown was maximized to the extent possible. Power was maintained below 50 percent for a longer than normal hold of 36 hours to allow the sulfate concentration to decrease. The operating experience was subsequently shared with the industry with the recommendation that cooldown to cold shutdown be considered during extended shutdowns to prevent the sulfate desorption phenomenon.

5. In May 2015 following the startup of Unit 1 from a refueling outage, reactor coolant system chloride concentration increased to a level close to the threshold at which chemistry performance metrics would be negatively affected, although still with significant margin to the specification.

   The cause of the elevated chloride concentration was attributed to chloride release from the mixed bed resin. As reactor coolant system boron concentration increased, the borate ions competed with chloride for anion exchange sites on the resin, causing some chloride to be released from the resin. Chloride exists on the resin sites due to the manufacturing process.

   The certificate of analysis from the vendor documented that the chloride fraction was less than the specification value, however, the resin was not shipped to the site until 15 months later. Subsequent testing by the vendor on remaining resin in storage from the same lot detected a chloride fraction greater than the specification. It was determined that the chloride fraction in the resin increased during that time due to hydrolysis while in storage.

As a corrective action, the procurement specification was revised to reduce the maximum acceptable chloride fraction for anion resin overlay lots to provide more margin should future resin lots be in storage for an extended period of time.

6. In August 2015, Chemistry personnel participated in a self-assessment that examined the conduct of chemistry procedure at a peer utility. Following the assessment, Chemistry personnel performed a comparison between the North Anna conduct of chemistry procedure and the peer utility conduct of chemistry procedure to identify any potential improvements to the North Anna procedure.

   The comparison found that all aspects of the peer utility procedure were already addressed in the North Anna procedure, and in most cases, the North Anna procedure provided a greater level of detail, thus no program changes were recommended.

7. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

8. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the Chemistry Control Program for Primary Systems AMA (UFSAR Section 18.2.4) and the Chemistry Control Program for Secondary Systems AMA (UFSAR Section 18.2.5).

9. In January 2019, following maintenance on the condensate polishing system, the system supply and return header isolation valves were opened as part of system restoration. Within minutes, the feedwater and steam generator sodium values increased rapidly and exceeded the program limits. The supply and return header isolation valves were closed and steam generator blowdown was maximized to reduce the concentrations. The following day, the sodium concentrations were restored to values below the established program threshold. Further investigation determined that the sodium source was a bearing cooling sample cooler. The leaking sample cooler was isolated and will remain isolated pending system replacement via design change package.

10. In April 2019, effectiveness reviews were performed on the Chemistry Control Program for Primary Systems AMA (UFSAR Section 18.2.4) and the Chemistry Control Program for Secondary Systems AMA (UFSAR Section 18.2.5). The AMAs were evaluated against the performance criteria identified in NEI 14-12, "Aging Management Program Effectiveness." No gaps were identified by the effectiveness reviews.

The above examples of operating experience provide objective evidence that the *Water Chemistry* program includes activities to control chemistry parameters in treated water environments to manage cracking, loss of material, reduction of heat transfer, and wall thinning of components exposed to a reactor coolant, steam, treated borated water, and treated water environments within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Water Chemistry* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Water Chemistry* program will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Water Chemistry* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.3 Reactor Head Closure Stud Bolting

Program Description

The *Reactor Head Closure Stud Bolting* program is an existing condition monitoring program that manages cracking and loss of material of the reactor head closure stud assembly (closure studs, nuts and washers) and for the threads in the reactor vessel flange.

The Reactor Head Closure Stud Bolting program is implemented as part of the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1). The program is consistent with the examination and inspection requirements specified in ASME Code, Section XI, Subsection IWB, Table IWB-2500-1, Category B-G-1. The current Unit 1 Inservice Inspection (ISI) Program for the fifth 10-year inspection interval is based on the 2013 Edition of the ASME Code, Section XI, with no addenda. The current Unit 2 ISI Program for the fourth 10-year inspection interval is based on the 2004 Edition of the ASME Code, Section XI, with no addenda. Future 120-month inspection intervals will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a 12 months before the start of the ISI inspection interval. The Reactor Head Closure Stud Bolting program includes preventive measures to address reactor head closure stud bolting degradation consistent with those identified in the Regulatory Guide (RG) 1.65, Revision 1, “Material and Inspection for Reactor Vessel Closure Studs.”

The Reactor Head Closure Stud Bolting program uses visual and volumetric examinations in accordance with the general requirements of ASME Code, Section XI, Article IWA-2000. The closure studs and threads in the reactor vessel flange receive a volumetric examination (with exceptions as allowed by NRC approved relief requests to eliminate volumetric examinations of the flange threads during the fourth inspection intervals), and the surfaces of nuts and washers at the reactor vessel flange are inspected using a visual examination (VT-1). Pressure boundary retaining components in examination category B-P receive a visual examination (VT-2) during system leakage tests and system hydrostatic tests.

Preventive measures for the Reactor Head Closure Stud Bolting program include the following attributes:

- No metal plating is used on the studs.
- Phosphated surface treatment is used on the studs.
- Fel-Pro N-5000 or Neolube® is used to lubricate the studs (precluding the use of molybdenum sulfides).

The material used for the reactor head closure studs, nuts and washers (and spares) is ASTM SA-540, Grade B24, Class 3. The procurement documents for this equipment did not require the material to have a measured yield strength value of less than 150 ksi or an ultimate tensile strength value of less than 170 ksi. For the two units, a total of 14 spare reactor head closure studs were procured; two with the General Reactor Vessel Specification (OEM) in 1967, two in 1993, and 10 in 2013. Only the two spares procured in 1993 (one of which was installed in 2017 in Unit 2 due to a non-age related event) include supporting documentation to validate a measured yield strength value of less than 150 ksi and an ultimate tensile strength value of less than 170 ksi. As a result, all installed studs except one and 12 of the 13 spares present a potential concern for stress corrosion cracking (SCC) based on the limits stipulated in RG 1.65, Revision 1.

To address the potential for SCC for the reactor head closure studs that are being used, ultrasonic examinations are performed during each ASME Code, Section XI, inspection interval. For 12 of the 13 spare studs that have strength values that could exceed the RG 1.65 limits of 150 and 170 ksi, the potential for SCC will not be a concern unless those spares were to be placed into service. At that time, the potential for SCC will be addressed by the ultrasonic examinations which continue to be performed in accordance with ASME Code, Section XI.

Any indication of degradation in reactor head closure stud bolting is evaluated in accordance with ASME Code, Section XI, Subsection IWB-3100, by comparing ISI results with the acceptance standards of ASME Code, Section XI, Subsections IWB-3400 and IWB-3500.

The *Reactor Head Closure Stud Bolting* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *Reactor Head Closure Stud Bolting* program is an existing program that is consistent, with exception, to NUREG-2191, Section XI.M3, Reactor Head Closure Stud Bolting.

Exception Summary

The following program element(s) are affected:

Preventive Actions (Element 2) and Corrective Actions (Element 7)

1. NUREG-2191 indicates in Section XI.M3, Reactor Head Closure Stud Bolting, that the program relies on the recommendations of RG 1.65, Revision 1, April 2010. RG 1.65, Revision 1, recommends that actual measured yield strength should not exceed 150 ksi for newly installed studs or 170 ksi ultimate tensile strength for existing studs. The installed and spare reactor head closure studs were not procured under specifications that limited the measured maximum yield and ultimate tensile strengths, which presents a concern for SCC. Therefore, the program takes exception to the recommendation that measured yield strength

should not exceed 150 ksi for newly installed studs or 170 ksi ultimate tensile strength for existing studs.

Justification for Exception

Cracking has been identified as an aging effect requiring management for the Unit 1 and 2 reactor head closure studs. The volumetric examination method in place for stud inspection per ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 is appropriate to identify cracking. There have been no recordable cracking indications identified by ISI program examinations of reactor head closure bolting components, indicating that the current program has been effective to manage cracking. The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1) will continue to include volumetric examination per ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1, and therefore will continue to be effective in managing cracking during the subsequent period of extended operation for existing studs and for spare studs upon installation.

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Reactor Head Closure Stud Bolting* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In March 2012, during cleaning and inspection of the Unit 1 reactor head closure studs, stud number 32 was found to have approximately a two-foot pitted area down the length of the stud in the non-threaded area. Exposure to boric acid was suspected as the cause of the pitting, but no residue was found. To further investigate, Engineering inspected the reactor vessel head flange and adjacent areas of the reactor vessel head with particular focus on stud hole number 32. No indication of leakage or boric acid was seen and no corrosion or wastage of material was observed at this location or the adjacent area. The pitting in the non-threaded area of the stud had become apparent during this inspection as a result of initiation of a new cleaning process which provided improved cleaning for that area of the stud. Based on ultrasonic and magnetic particle examinations that showed no indications, stud number 32 was determined to be acceptable for reuse and was returned to service. During the following Fall 2013 Unit 1 refueling outage, the pitting on stud number 32 was reexamined and the stud was again determined to be acceptable for reuse and was returned to service. The procedure governing cleaning of the reactor vessel studs was revised to add notes and directions throughout the procedure to explain previous discrepancies documented and evaluated as satisfactory

associated with stud number 32 such that these discrepancies would not have to be readdressed during subsequent inspections.

2. In March 2012, during cleaning and inspection of the Unit 1 reactor head closure studs, stud number 34 was found to have a minor surface defect in the lower portion of the non-threaded area measuring approximately 3/8 inches long by 1/32 inches wide by 0.008 inches deep. A depression was also observed on the lower portion of the shank that was recessed approximately 0.005 inches below the rest of the bolt outside diameter when measured using a straight edge and feeler gauges. The depression area was approximately 1.5 inches in height and spanned about 90 degrees around the circumference of the shank. Volumetric examination (Ultrasonic) showed no internal irregularities and magnetic particle examination identified the minor surface defect which was determined to not affect the stud's strength or its ability to provide clamping force on the reactor head. Engineering evaluated stud number 34 based on the nondestructive examination results and concluded that the as-found condition was acceptable for reuse and stud number 34 was returned to service. During the following Fall 2013 Unit 1 refueling outage, the minor surface defect and depression area on stud number 34 were reexamined and the stud was again determined to be acceptable for reuse and was returned to service. The procedure governing cleaning of the reactor vessel studs was revised to add notes and directions throughout the procedure to explain previous discrepancies documented and evaluated as satisfactory associated with stud number 34 such that these discrepancies would not have to be readdressed during subsequent inspections.

3. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion was reached that no performance deficiencies or learning opportunities were identified for the ISI Program - Reactor Vessel AMA (UFSAR Section 18.2.13) related to reactor head closure stud bolting inspections.

4. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.

5. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the ISI Program - Reactor Vessel AMA (UFSAR Section 18.2.13) related to reactor head closure stud bolting inspections.
6. In April 2019, an effectiveness review was performed on the ISI Program - Reactor Vessel AMA (UFSAR Section 18.2.13) that includes reactor head closure stud bolting among its inspection activities. The AMA was evaluated against the performance criteria identified in NEI 14-12, "Aging Management Program Effectiveness." No gaps were identified by the effectiveness review related to reactor head closure stud bolting inspections.

The above examples of operating experience provide objective evidence that the *Reactor Head Closure Stud Bolting* program includes activities to perform volumetric and visual inspections to manage cracking and loss of material of the reactor head closure stud assembly (closure studs, nuts, washers and the threads in the reactor vessel flange) within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Reactor Head Closure Stud Bolting* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Reactor Head Closure Stud Bolting* program will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Reactor Head Closure Stud Bolting* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.4 Boric Acid Corrosion

Program Description

The *Boric Acid Corrosion* program is an existing condition monitoring program that manages loss of material due to leaking borated water on structures and components (including electrical equipment/junction boxes) within the scope of subsequent license renewal that are susceptible to boric acid corrosion. The program includes provisions to identify leakage through inspection and examination. When leakage is identified, a visual inspection is performed that identifies the leakage pathway and any boric acid residue on adjacent structures, components, and supports so that leakage clean-up can begin, and corrective actions can be initiated, as necessary. When it is determined that an evaluation is necessary, it is performed in a timely manner. Follow-up inspections may be performed to ensure that the corrective actions were adequate and addressed the identified age-related degradation.

The *Boric Acid Corrosion* program relies in part on Generic Letter 88-05 (GL 88-05), “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants,” for guidance to identify, evaluate, and correct borated water leaks that could cause corrosion damage to reactor coolant pressure boundary components. Borated water leakage from components outside the scope of the program established in response to GL 88-05 may affect components within the scope of subsequent license renewal. Therefore, this program includes components within the scope of subsequent license renewal exposed to an air environment with borated water leakage that are susceptible to boric acid corrosion.

The *Boric Acid Corrosion* program is consistent with Section 7 of WCAP-15988-NP, Revision 2, “Generic Guidance for an Effective Boric Acid Inspection Program for Pressurized Water Reactors.” Additionally, the program includes examinations conducted during Inservice Inspection (ISI) pressure tests performed in accordance with ASME Code, Section XI requirements. Specific attributes from WCAP-15988-NP are addressed in implementing procedures.

The *Boric Acid Corrosion* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *Boric Acid Corrosion* program is an existing program that is consistent with NUREG-2191, Section XI.M10, Boric Acid Corrosion.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Boric Acid Corrosion* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In October 2011, during performance of a leak check of the low head safety injection (LHSI) system, a LHSI pump was found to have dry boric acid originating from the threaded connection of the vent line to the pump seal area and on the flange for the casing vent line. On the threaded connection, the boric acid was dry and white. On the flange, the boric acid was dry, but had some rust coloration in it and the threaded bolts included had a fair amount of oxidation. In accordance with the BACCP, Engineering performed an evaluation to determine the extent of any boric acid degradation and required corrective actions for these components. Since the vent line and seal were stainless steel and not susceptible to boric acid corrosion, and no targets were affected, it was determined that no BACCP evaluation was required for these components. For the flange evaluation, the boric acid was cleaned and the surface condition of the fasteners examined. The worst condition, identified on one fastener, determined no wastage of the throat thickness was evident. The corrosion rate of carbon steel due to boric acid in this mild environment was determined to be negligible and the flange was added to the BACCP Monitor List for periodic inspections. In April 2013, the flange was disassembled, cleaned and the gasket seating surface was inspected. A new gasket and new fasteners were installed upon reassembly.
2. In December 2014, an assessment was performed to evaluate the BACCP against industry standards, strengths, and good practices, and to determine procedural and regulatory compliance. The fleet program documents were assessed to be compliant with regulatory commitments, as well as mandatory and needed NEI 03-08, Revision 2, “Guideline for the Management of Materials Issues,” industry requirements. Other aspects of the evaluation were to determine whether boric acid leakage is promptly identified and documented in the Corrective Action Program, to determine whether boric acid leakage evaluations are performed and documented in a timely manner, to determine whether minor leaks are cleaned and regularly monitored for change in condition, and to determine whether safety significant/excessive leakage is corrected/mitigated in a timely manner. The assessment confirmed that these functions are being completed effectively and none of the procedure

enhancements suggested as a result of the assessment were required. No further actions were required to be taken.

3. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion was reached that no performance deficiencies or learning opportunities were identified for the Boric Acid Corrosion Surveillance AMA (UFSAR Section 18.2.3).

4. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

5. In April 2017, it was identified that an ASME Class 3 flow control valve in the emergency boration flow path, which had been on the BACCP Monitor List and inspected once a quarter for leakage since September of 2015, did not have a current formal BACCP evaluation on file. In May 2017, Engineering completed the formal evaluation which summarized the extent of any boric acid degradation and specified required corrective actions. Work orders were initiated and scheduled for the upcoming Unit 1 refueling outage to address the leakage and monitoring of the valve was increased to once per month until the valve was rebuilt in March 2018.

6. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the Boric Acid Corrosion Surveillance AMA (UFSAR Section 18.2.3).

7. In September 2017, a visual inspection of reactor coolant pressure boundary components during refueling identified boric acid leakage from the body to bonnet gasket on a reactor coolant loop hot leg isolation valve. In accordance with ASME Code, Section XI, Subsection IWA-5250, one bolt was to be removed, a visual (VT-3) exam completed, and evaluation performed in accordance with ASME Code, Section XI, Subsection IWA-3100. However, Code Case N-566-2 was invoked as an alternative to IWA-5250(a)(2). As stated in

the evaluation per Code Case N-566-2, it was determined that no need existed for removing any of the bolting associated with this valve to perform a VT-3 examination. There was no significant corrosion or visible damage on any of the bolting. Based on bolting material loss calculations the valve was repaired in March 2019.

8. In April 2019, an effectiveness review was performed on the Boric Acid Corrosion Surveillance AMA (UFSAR Section 18.2.3). The AMA was evaluated against the performance criteria identified in NEI 14-12, “Aging Management Program Effectiveness.” No gaps were identified by the effectiveness review.

The above examples of operating experience provide objective evidence that the *Boric Acid Corrosion* program includes activities to perform visual inspections to identify loss of material due to leaking borated water for structures and components (including electrical equipment/junction boxes) within the scope of subsequent license renewal that are susceptible to boric acid corrosion, and to initiate corrective actions. Occurrences identified under the *Boric Acid Corrosion* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Boric Acid Corrosion* program will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Boric Acid Corrosion* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.5 Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components

Program Description

The *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program is an existing condition monitoring program that manages cracking due to primary water stress corrosion cracking (PWSCC) for components or welds constructed from Alloy 600/82/182 and exposed to pressurized water reactor (PWR) primary coolant at elevated temperatures. Initiation and growth of PWSCC cracks can occur as a function of variables which include, but are not limited to temperature, stress, microstructure, time, and water chemistry. This program is used in conjunction with the *Water Chemistry* program (B2.1.2).

The *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program is patterned after the industry guidance document, MRP-126, “Materials Reliability Program: Generic Guidance for Alloy 600 Management.” Bare-metal visual, surface, and volumetric examinations are used to detect the presence of PWSCC. Examinations are performed periodically.

The nickel-alloy components that are examined due to susceptibility to PWSCC include the reactor vessel bottom-mounted instrumentation nozzles and J-groove welds (ASME Code Case N-722, as incorporated by reference in 10 CFR 50.55a), the Unit 1 and Unit 2 steam generator cold leg (CL) nozzle butter and welds (ASME Code Cases N-722 and N-770 (Category B), as incorporated by reference in 10 CFR 50.55a), and the Unit 2 steam generator hot leg (HL) nozzle butter and welds (ASME Code Cases N-722 and N-770 (Category A), as incorporated by reference in 10 CFR 50.55a). Nickel alloy components for which PWSCC has been mitigated by use of a full structural weld overlay (FSWOL) of Alloy 52/152 material, including the Unit 1 and Unit 2 pressurizer surge, spray, safety, and relief nozzle butter and welds and the Unit 1 steam generator HL nozzle butter and welds, are examined (ASME Code Case N-770 (Category F), as incorporated by reference in 10 CFR 50.55a). Other nickel-alloy components that are examined, but are resistant to PWSCC, include the reactor vessel head penetration nozzles and J-groove welds (ASME Code Case N-729, as incorporated by reference in 10 CFR 50.55a). There are no susceptible nickel-alloy branch line connections that would require a baseline volumetric or inner diameter surface examination in accordance with ASME Code Case N-770, as incorporated by reference in 10 CFR 50.55a.

The *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program examines components that are susceptible to loss of material due to boric acid leakage from nearby or adjacent nickel-alloy components previously described. Findings of boric acid on Alloy 600/82/182 components are documented in accordance with the *Boric Acid Corrosion* program (B2.1.4).

The *Water Chemistry* program (B2.1.2) monitors and controls water environments consistent with industry guidelines to ensure that the reactor coolant water environments are favorable to mitigate PWSCC in nickel-alloy components.

The *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program is an existing program that is consistent 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.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience (OE) provide objective evidence that the *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. Bare metal visual (BMV) examinations were performed on the Unit 1 bottom-mounted instrumentation (BMI) nozzles every outage from Fall 2004 to Fall 2007 and every other outage after Fall 2007. BMV examinations were performed on the Unit 2 BMI nozzles every

outage from Spring 2004 to Spring 2010 and every other outage after Spring 2010. There was no evidence of cracking identified during the BMV examinations of the BMI nozzles for both units.

2. In January 2003 and April 2003, the reactor vessel closure heads (RVCHs) were replaced for Units 2 and 1, respectively. Subsequently, BMV examinations of the RVCHs were performed Fall 2007, Spring 2012, and Fall 2016 for Unit 1, and Spring 2007, Fall 2011, and Spring 2016 for Unit 2. No evidence of cracking of the RVCHs was found during these examinations.

   Volumetric examinations of the nozzle penetrations were performed in Spring 2007 for Unit 2 and Spring 2012 for Unit 1 with no relevant indications identified.

3. In Spring 2007 and Fall 2007, Full Structural Weld Overlays (FSWOLs) using a PWSCC resistant weld material were installed on the pressurizer surge, spray, safety and relief nozzle dissimilar metal (DM) welds for Units 2 and 1, respectively. Subsequent to installation of the FSWOLs, volumetric examinations were performed as follows:
   - Spring 2009 - Unit 1 pressurizer nozzle to safe end DM welds (all);
   - Fall 2008 - Unit 2 pressurizer nozzle to safe end DM welds (all);
   - Fall 2011 - Unit 2 safety nozzle to safe end DM welds (2 of 3);
   - Spring 2012 - Unit 1 pressurizer surge nozzle to safe end DM weld; and
   - Fall 2013 - Unit 1 pressurizer nozzle to safe end DM welds (all except the surge nozzle to safe end DM weld)

   No relevant indications were identified during these examinations.

4. Periodic visual examinations were performed on the Unit 1 steam generator CL nozzle DM welds through Fall 2010 with no evidence of cracking identified. Volumetric examinations of the Unit 1 steam generator CL nozzle DM welds were performed in Spring 2009, Spring 2012, and Spring 2015. No relevant indications were identified.

5. Periodic visual examinations were performed on the Unit 1 steam generator HL nozzle DM welds through Fall 2010 with no evidence of cracking identified. In Spring 2012, FSWOLs using PWSCC resistant weld material were installed on the Unit 1 steam generator HL nozzle DM welds. Volumetric examinations of the HL nozzle DM welds were performed Spring 2015. No relevant indications were identified.

   Note: During installation of the FSWOLs, two through-wall cracks were identified in the Unit 1 'B' steam generator HL safe-end to nozzle weld. See the March 2012 operating experience for a more detailed discussion.

6. Bare metal visual examinations are currently performed every outage for Unit 2 steam generator HL nozzle dissimilar welds and at least once per interval for the Unit 2 steam

generator CL nozzle DM welds (except when ultrasonic examinations are performed). Visual examinations performed to date have not identified any evidence of cracking. Volumetric examinations were performed as follows:

- Spring 2007 - Unit 2 'B' steam generator HL and CL nozzle DM welds;
- Fall 2008 - Unit 2 'C' steam generator HL and CL nozzle DM welds;
- Spring 2013 - Unit 2 'A', 'B', and 'C' steam generator HL and CL nozzle DM welds;
- Fall 2014 - Unit 2 'C' steam generator HL and CL nozzle DM welds; and
- Fall 2017 - Unit 2 'A', 'B', and 'C' steam generator HL nozzle DM welds

No relevant indications were identified for these examinations.

For the Unit 2 steam generator cold legs, Alternative Request N2-I4-NDE-007 (ML19039A236) authorized the use of a one time-extension of the volumetric examination from Spring 2019 to Spring 2022.

7. In March 2012, during machining activities for installation of a full structural weld overlay (FSWOL) on the Unit 1 'B' loop steam generator hot leg (HL) primary nozzle dissimilar metal (DM) weld, two cracks were identified in the safe-end to nozzle DM weld. As required by ASME Code, Section XI, additional ultrasonic testing (UT) examinations were performed on the weld, area, or parts of similar material and service. As a result of this operating experience, the management strategies for Alloy 600 components were reviewed and were determined to be appropriate. In addition, UT examinations were performed on the U1 'B' SG HL DM weld region in question and it was concluded that the pre-FSWOL UT examination should have identified both indications. Benchmarking of industry practices was performed to establish industry best practices for the effective implementation of NDE for DM welds. Following the Benchmarking, results of a Root Cause Evaluation identified application of existing NDE processes as not being effective. As a result, Dominion Fleet NDE procedures were revised/developed to capture current identified industry best practices for NDE implementation improvements by requiring the following for Supplemental NDE Personnel:

   - Indoctrination to Dominion NDE Program Requirements
   - Performance of Pre-Job Briefings and Post-Job Critiques for NDE Activities
   - Dominion NDE Personnel Oversight during Job-site NDE Activities

   There was no impact on the FSWOL design.

8. In September 2011, as a result of a corporate audit of the Inservice Inspection (ISI) Program, the “Alloy 600 Management Plan” was revised to incorporate a recommendation to remove non-Alloy 600/690 items and to add further information relative to examinations of Alloy 600 locations.

9. In October 2012, as part of an industry review, the Materials Degradation Management Program (MDMP) was reviewed to assess the effectiveness of the Boric Acid Corrosion Control Program (BACCP) and the station intolerance to degraded material conditions. In addition, the MDMP review evaluated the effectiveness of station personnel identification and mitigation of vulnerabilities associated with the use of Alloy 600. As a result, NEI 03-08, "Guideline for the Management for Material Issues," "Needed" guidance for calculating RCS leak rate was confirmed as being appropriately incorporated into the North Anna procedures.
10. In December 2018, the U.S. Nuclear Regulatory Commission (NRC) issued Regulatory Issue Summary RIS-2018-06, "Clarification of the Requirements for Reactor Pressure Vessel Upper Head Bare Metal Visual Examinations" to clarify 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, "Alternative Examination Requirements for PWR Reactor Vessel Upper Heads with Nozzles Having Pressure-Retaining Partial-Penetration Welds Section XI, Division 1." As identified in the RIS, two recent events illustrate how the requirements of Code Case N-729-4 can be misinterpreted by licensees. This operating experience was reviewed and it was determined that the guidance as prescribed was being followed. As a result of this OE, the corporate procedure for performing the bare metal visual examinations was revised to reference NRC RIS 2018-06 and related EPRI Report 3002013268, "Materials Reliability Program: Visual Examination for Leakage of PWR Reactor Vessel Upper Head Nozzles (MRP-60 Revision 5)."

The above examples of operating experience provide objective evidence that the *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program includes activities to perform visual and volumetric examinations to detect cracking due to PWSCC and loss of material for Alloy 600/82/182 components or welds within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.6 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)

Program Description

The *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* program is an existing condition monitoring program that manages loss of fracture toughness of cast austenitic stainless steel reactor coolant pressure boundary components with service conditions above 250°C (Celsius) [482°F (Fahrenheit)].

The program consists of the determination of the susceptibility of cast austenitic stainless steel (CASS) piping and piping components in reactor coolant pressure boundaries with regard to thermal aging embrittlement based on the casting method, molybdenum content, and percent ferrite. Only high molybdenum, statically cast pipe fittings with greater than 14% ferrite were screened-in as potentially susceptible and requiring further evaluation.

Aging management of potentially susceptible piping and piping components is accomplished through a component-specific flaw tolerance evaluation using the evaluation procedures and acceptance criteria contained in ASME Code, Section XI, Appendix C or ASME Code Case N-838, as applicable based on delta ferrite content. ASME Code Case N-838 is used for components with delta ferrite over 20% but no greater than 25%. Based on certified material test report (CMTR) data, one heat was identified with a “ladle” delta ferrite of less than 25% and a “check” delta ferrite of greater than 25%. For this heat of material with a delta ferrite greater than 25%, the flaw acceptance criteria for Category 2 welds as provided in the 2019 Edition of ASME Code, Section XI, Appendix C, Article C-6000 are used. As identified in Table C-6330-1 of this Article, the Category 2 weld Z-factor for delta ferrite greater than 25% is a more stringent penalty factor compared to the SAW Z-factor for delta ferrite between 14% and 25%. Based on the plant specific flaw tolerance evaluation documented in WCAP-18506, “Flaw Tolerance Evaluation for Susceptible Reactor Coolant Loop Cast Austenitic Stainless Steel Elbow Components for North Anna Units 1 and 2,” flaw crack growth remains acceptable for the subsequent period of extended operation.

For valve bodies, based on the results of the assessment documented in the letter dated May 19, 2000, from Christopher Grimes, U.S. Nuclear Regulatory Commission (NRC), to Douglas Walters, Nuclear Energy Institute (May 19, 2000 NRC letter), screening for significance of thermal aging embrittlement is not required. The existing ASME Code, Section XI visual inspection requirements are adequate for valve bodies.

The existing ASME Code, Section XI inspections of the reactor coolant pump casings include a VT-3 visual examination of the internal surfaces whenever a reactor coolant pump is disassembled for maintenance. The existing ASME Code, Section XI visual inspection requirements are adequate for managing the aging effects of reactor coolant pump casings because the original flaw tolerance evaluation performed as part of Code Case N-481 remains bounding and is applicable for the subsequent period of extended operation as detailed in SLRA Section 4.7.6.

The *PWR Vessel Internals* program (B2.1.7) manages the aging of CASS reactor vessel RVI components.

NUREG-2191 Consistency

The *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* program is an existing program that is consistent with NUREG-2191, Section XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) as modified by SLR-ISG-Mechanical-2020-XX, Updated Aging Management Criteria for Mechanical Portions of the Subsequent License Renewal Guidance.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 2012, during Unit 1 refueling outage, as part of the Unit 1 Risk-Informed ISI program, in the reactor coolant loop ‘B’ hot leg, the CASS elbow to '1B' steam generator inlet nozzle safe end weld was volumetrically examined with no relevant indications identified.
2. In September 2014, during Unit 2 refueling outage, as part of the Unit 2 Risk-Informed ISI program, in the reactor coolant loop ‘B’ crossover leg, the CASS pipe to CASS elbow and CASS elbow to '1B' reactor coolant pump inlet welds were volumetrically examined with no relevant indications identified.
3. In September 2016, during Unit 1 refueling outage, as part of the Unit 1 Risk-Informed ISI program, in the reactor coolant loop ‘C’ cold leg, the '1C' CASS reactor coolant pump outlet to CASS pipe weld and a CASS pipe to boss fitting weld were examined with no relevant indications identified. Also, as part of the Unit 1 Risk-Informed ISI program, in the reactor coolant loop ‘C’ hot leg, the CASS elbow to hot leg isolation valve weld was volumetrically examined with no relevant indications identified.

4. In March 2019, during Unit 2 refueling outage, as part of the Unit 2 Risk-Informed ISI program, volumetric examinations were performed on a CASS pipe to pipe weld in the reactor coolant loop ‘C’ cold leg, the CASS elbow to steam generator safe end weld in the reactor coolant loop ‘C’ hot leg, a CASS pipe to CASS elbow weld in the reactor coolant loop ‘C’ hot leg, and the 14" branch pipe to CASS pipe weld in the reactor coolant loop ‘C’ hot leg with no relevant indications identified.

The above examples of operating experience provide objective evidence that the *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* program includes activities to perform inspections that meet ASME Code, Section XI inspection requirements to identify and manage loss of fracture toughness with regard to thermal aging embrittlement of the susceptible components within the scope of subsequent license renewal. Occurrences identified under the *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* program will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.7 PWR Vessel Internals

Program Description

The *PWR Vessel Internals* program is an existing condition monitoring program that manages change in dimensions due to void swelling, cracking, loss of fracture toughness, loss of material, and loss of preload for the reactor vessel internals (RVI). The aging effect of cracking includes stress corrosion cracking, primary water stress corrosion cracking, irradiation-assisted stress corrosion cracking, and cracking due to fatigue/cyclic loading. Degradation due to loss of material can be induced by wear, and loss of fracture toughness is the result of thermal aging and neutron irradiation embrittlement. Potential causes for the aging effect of changes in dimensions are void swelling or distortion, and loss of preload can result from thermal and irradiation-enhanced stress relaxation or creep.

The *PWR Vessel Internals* program relies on implementation of the inspection and evaluation guidelines in Electric Power Research Institute (EPRI) Technical Report 3002017168, “Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227, Revision 1-A),” (ADAMS Accession No. ML19339G364) and EPRI Technical Report 3002010399, “Materials Reliability Program: Inspection Standard for Pressurized Water Reactor Internals - 2018 Update (MRP-228, Rev. 3),” (ADAMS Accession No. ML19081A057) to manage the aging effects on the reactor vessel internal components, as supplemented by a gap analysis. The guidelines listed in MRP-227, Revision 1-A, provide an appropriate aging management methodology for the RVI components up to a 60-year operating period. The EPRI basis document that provides functionality analyses for the aging management methodology is Technical Report 3002007955, “Materials Reliability Program: Functionality Analysis for Westinghouse and Combustion Engineering Representative PWR Internals (MRP-230, Revision 2, Supplement 1)” (ADAMS Accession No. ML17289A507). The failure modes, effects, and criticality analysis from EPRI Technical Report 3002013220, “Materials Reliability Program: Screening, Categorization, and Ranking of Reactor Internals Components for Westinghouse and Combustion Engineering PWR Designs (MRP-191, Revision 2)” (ADAMS Accession No. ML19081A057) provides the basis for grouping the reactor internals components into inspection categories by assessing aging effects and relevant time-dependent aging parameters.

For the 80-year operating period, aging management is based on the EPRI documents listed for the 60-year period, and a gap analysis that integrates the interim guidance from MRP 2018-022, “Transmittal of MRP-191 Screening, Ranking, and Categorization Results and Interim Guidance in Support of Subsequent License Renewal at U.S. PWR Plants,” (ADAMS Accession No. ML19081A061) for additional inspections not listed in MRP-227, Revision 1-A.

The results from the gap analysis are shown below:

- The following listing identifies the changes that are included in the *PWR Vessel Internals* program based on MRP 2018-022:
    a. Clevis insert bolts (Alignment and Interfacing Components) were elevated from Existing Programs component to Primary component. The scope of this item was expanded to include the clevis insert dowels.
    b. Thermal sleeves (Alignment and Interfacing Components) were added as a Primary component.
    c. Radial support keys Stellite™ wear surface (Radial Support Keys) was added as a Primary component.
    d. Clevis bearing Stellite™ wear surface (Alignment and Interfacing Components) was added as a Primary component.
    e. Fuel alignment pins (Malcomized) (Upper Internals Assembly) were added as an Existing Programs component.
    f. Fuel alignment pins (Malcomized) (Lower Internals Assembly) were added as an Existing Programs component.
- For the 80-year operating period, the gap analysis further integrates guidance for inspections of the following components:
    a. Control rod guide tube (CRGT) assembly continuous section sheath and C-tube (CRGT Assembly) expansion component inspections in accordance with WCAP-17451-P, Revision 2, “Reactor Internals Guide Tube Wear - Westinghouse Domestic Fleet Operational Projections” (ADAMS Accession No. ML19262E593).
    b. One-time inspections of the core barrel middle axial weld (MAW) and lower axial weld (LAW) (Core Barrel Assembly) primary component inspections in accordance with guidance provided in 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” (ADAMS Accession No. ML19249B102).

The selection of RVI components to be inspected is based on a four-step ranking process that includes the designations of “Primary”, “Expansion”, and “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), and “no additional measures”. The program includes expanding examinations (i.e., “expansion” components) if the observed extent of degradation for the “primary” components exceeds acceptance criteria. The identified examinations for RVI components provide reasonable assurance that the effects of age-related degradation mechanisms will be managed during the subsequent period of extended operation.

The *PWR Vessel Internals* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *PWR Vessel Internals* program is an existing program that, following enhancement, will be consistent, with NUREG-2191, Section XI.M16A, PWR Vessel Internals.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Detection of Aging Effects (Element 4)

1. Procedures will be revised to provide guidance for inspections of the following reactor vessel internal components in accordance with the referenced report for each item:
    a. Control rod guide tube (CRGT) lower flange weld (MRP-227, Revision 1-A, “Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines”)
    b. CRGT guide plates (cards) (MRP-227, Revision 1-A)
    c. Core barrel upper flange weld (UFW) (MRP-227, Revision 1-A)
    d. Core barrel lower girth weld (LGW) (MRP-227, Revision 1-A)
    e. Core barrel middle axial weld (MAW) and lower axial weld (LAW) (MRP-227, Revision 1-A)
    f. Core barrel upper axial weld (UAW) (MRP-227, Revision 1-A)
    g. Core barrel upper girth weld (UGW) (MRP-227, Revision 1-A)
    h. Core barrel lower flange weld (LFW) (MRP-227, Revision 1-A)
    i. Baffle-edge bolts (MRP-227, Revision 1-A)
    j. Baffle plates (MRP-227, Revision 1-A)
    k. Baffle-former bolts (MRP-227, Revision 1-A)
    l. Barrel-former bolts (MRP-227, Revision 1-A)

m. Bottom-mounted instrumentation column bodies (MRP-227, Revision 1-A)

n. Lower support column bodies (MRP-227, Revision 1-A)

o. Lower support column bolts (MRP-227, Revision 1-A)

p. Clevis insert bolts (MRP 2018-022, “Transmittal of MRP-191 Screening, Ranking, and Categorization Results and Interim Guidance in Support of Subsequent License Renewal at U.S. PWR Plants”)

q. Clevis insert dowels (MRP 2018-022)

r. Stellite™ wear surface on radial support keys (MRP 2018-022)

s. Stellite™ wear surface on clevis inserts (MRP 2018-022)

t. Fuel alignment pins for lower core plate (MRP 2018-022)

u. Fuel alignment pins for upper core plate (MRP 2018-022)

2. Procedures will be revised to provide guidance for inspections of the CRGT continuous section sheaths and C-tubes in accordance with WCAP-17451-P, Revision 2, “Reactor Internals Guide Tube Wear – Westinghouse Domestic Fleet Operational Projections”.

Detection of Aging Effects (Element 4) and Acceptance Criteria (Element 6)

3. Procedures will be revised to provide acceptance criteria for inspection results for the following reactor vessel internal components in accordance with MRP-227, Revision 1-A:

   a. Thermal shield flexures

   b. Lower support forging

   c. Upper core plate

4. Procedures will be revised to provide guidance for one-time inspections of the core barrel MAW and LAW in accordance with 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”.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *PWR Vessel Internals* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 2010, during the Unit 2 reactor vessel 10-year inservice inspection, slight damage was noted in the vessel core barrel keyways at 0° and 90°. The keyways were bright and shiny indicating a recent rub when the core barrel was pulled. An Engineering evaluation was

performed in accordance with ASME Code, Section XI requirements for visual examinations (VT-3). Viewing the areas from varying angles and directions indicated that the areas were localized to the surface without any gouging or depth. These localized shiny areas were not considered recordable VT-3 indications.

2. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion was reached that no performance deficiencies or learning opportunities were identified for the Reactor Vessel Internals Inspection AMA (UFSAR Section 18.2.15).
3. In September 2016, during the Unit 1 refueling outage, the core barrel baffle-to-former bolts were examined. Of the 1088 bolts, 1081 were examined, and three bolts determined to contain flaw indications. The remaining seven bolts could not be tested due to locking bars preventing proper contact with the bolt heads. The locking bars and welds were intact, and there was no indication of degradation. The recorded flaw conditions were determined to be acceptable in accordance with established criteria. The baffle-former assembly retained its structural integrity and continued to perform its intended function.
4. In September 2016, a tie-rod hole on Unit 1 control rod guide tube (CRGT) J-7, Card 7, was found to be oval instead of circular. This was a rejectable indication because the hole is shown as round on inspection documents. The suspected cause was a fabrication error that occurred when the pilot hole for the tie rod was drilled in the incorrect position. When a correction was made during fit-up, the tie-rod hole that should have been circular became oblong. There have been no other operational issues related to guide card wear, or control rod performance in rod drop and rod operability tests for this CRGT assembly. The CRGT J-7 continued to perform its intended function.
5. In December 2016, as part of the oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.

6. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP71003 NRC Phase II inspection to be conducted for Units 1 and 2 during November through December 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the Reactor Vessel Internals Inspection AMA (UFSAR Section 18.2.15).
7. In March 2018, during the Unit 1 10-year inservice inspection visual examinations of the reactor vessel radial support clevis inserts, wear was identified on the mating surfaces at 0°, 90°, 180° and 270°. Further investigation identified wear on the corresponding surfaces of the radial support keys. Wear was only identified on one side of the clevis and corresponding key. No wear was identified on the opposite side of the clevis insert or radial support key at any of these locations. The lower radial support components use an interference-fit between the clevis insert and the radial keys to provide structural support. The wear observed did not change the capability of the clevis inserts and radial support keys to perform their intended function.
8. In April 2019, an effectiveness review was performed on the Reactor Vessel Internals Inspection AMA (UFSAR Section 18.2.15). The AMA was evaluated against the performance criteria identified in NEI 14-12, “Aging Management Program Effectiveness”. No gaps were identified by the effectiveness review.
9. MRP-227-A Compliance Inspections

   Fall 2016 (Unit 1) and Spring 2019 (Unit 2) - During these dates, the initial phase of inspections were performed for MRP-227-A compliance, and included the following RVI components:

   - Control rod guide tube assembly guide cards
   - Control rod guide tube assembly upper and lower flange welds
   - Core barrel assembly upper flange weld
   - Core barrel assembly upper girth weld
   - Baffle-former assembly baffle-edge bolts
   - Baffle-former assembly baffle-former bolts
   - Baffle-former assembly baffle plates seams (examinations from the top and bottom of the formers for indications of void swelling or vertical displacement)
   - Alignment and interfacing components internals hold down spring

Spring 2018 (Unit 1) - The Phase 2 inspections were completed for MRP-227-A compliance, and included the following RVI components:

- Core barrel assembly lower girth weld
- Core barrel assembly lower flange weld
- Baffle-former assembly high-fluence baffle plates and seams (examination for evidence of warping or misalignment)
- Thermal shield assembly thermal shield flexures
- Core barrel lower radial support clevis inserts and cap screws, and the radial keys (including the Stellite™ wear surfaces)
- B-N-3 components
    - Core barrel flange
    - Upper support ring/upper support skirt
    - Lower core plate
    - Upper core plate alignment pins

[NOTE: *Similar Phase 2 RVI component inspections are scheduled to be performed for Unit 2*]

The above examples of operating experience provide objective evidence that the *PWR Vessel Internals* program includes activities to perform visual and volumetric examinations to identify change in dimensions due to void swelling, cracking, loss of fracture toughness, loss of material, and loss of preload for the reactor vessel internals (RVI) within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *PWR Vessel Internals* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *PWR Vessel Internals* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *PWR Vessel Internals* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.8 Flow-Accelerated Corrosion

Program Description

The *Flow-Accelerated Corrosion* program is an existing condition monitoring program that manages wall thinning caused by flow-accelerated corrosion, as well as wall thinning due to erosion mechanisms. Erosion monitoring is performed for the internal surfaces of metallic piping and components to manage the aging effect of wall thinning due to cavitation, flashing, liquid droplet impingement, and solid particle erosion.

The *Flow-Accelerated Corrosion* program is consistent with the Virginia Power response to NRC Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning," and relies on implementation of the EPRI guidelines in Nuclear Safety Analysis Center (NSAC)-202L, Revision 4, "Recommendations for an Effective Flow Accelerated Corrosion Program." The erosion activity implements the recommendations of EPRI 3002005530, "Recommendations for an Effective Program Against Erosive Attack".

The *Flow-Accelerated Corrosion* program includes (a) identifying flow accelerated corrosion (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 operating experience, 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 *Flow-Accelerated Corrosion* program tracks and predicts occurrences of wall thinning due to FAC using CHECWORKS-SFA™ software. Changes made in the CHECWORKS-SFA™ model are prepared and implemented by a qualified FAC engineer. Each change is then independently reviewed and validated by a qualified FAC engineer. Evaluations documenting the calculation of wear, wear rate, remaining life, next scheduled inspection, and sample expansion are independently reviewed by a qualified FAC engineer. The CHECWORKS-SFA™ model is evaluated and updated, as required, to reflect any significant changes in plant operating parameters such as power uprates. The CHECWORKS-SFA™ model is also refined by importing actual ultrasonic testing (UT) examination results as input for further wear rate analysis, thereby improving the predictive capability of the model for FAC-susceptible components included in the model. Wall thinning information available from the CHECWORKS-SFA™ software is one of the tools used to determine the scope and required schedule for inspections of FAC-susceptible components.

In addition to planned inspections performed for the *Flow-Accelerated Corrosion* program, opportunistic visual inspections of internal surfaces are conducted during routine maintenance activities to identify degradation. The *Flow-Accelerated Corrosion* program goal is to ensure that piping remains above the minimum allowable wall thickness; inspections are scheduled to support a planned approach such that the component wall thickness will be managed until replacement can be scheduled.

Erosion Monitoring Description

The basis for erosion monitoring is an Erosion Susceptibility Evaluation (ESE) that identifies components that require inspection due to potential wall thinning caused by cavitation, flashing, liquid droplet impingement (LDI), or solid particle erosion (SPE). The ESE includes each system that could be degraded by any of these four mechanisms. The majority of the erosion monitoring inspection scope is based on the ESE, and is determined in a manner similar to the process for "Susceptible Non-modeled" (SNM) lines used for the FAC program. Lines are risk ranked based on the level of plant safety, erosion susceptibility, and consequence of failure. An additional input for identifying the scope of inspections is an engineering evaluation of components that are not susceptible to erosion because of infrequent operation. In addition, the evaluation did not identify any situations of non-routine system alignments that could increase erosion susceptibility.

Identification of components to be inspected for erosion monitoring is provided by an Engineering evaluation that considers operating experience reviews, components replaced at other units, re-inspections of previously-inspected component, input from other internal inspections, and previously-replaced components. Erosion monitoring includes calculations of wear rate based on nominal and measured wall thickness values, evaluations of remaining service life, and determination of whether a component requires immediate replacement, a future re-inspection, or no further inspection.

The CHECWORKS Erosion Module is not used to determine susceptibility, or select systems for inspection. All lines modeled in the Erosion Module are identified using the ESE. The outputs from the Erosion Module are used to predict locations on susceptible lines. Those outputs are not used to exclude lines from the inspection scope, but are used to help establish the priority of inspections. Determination of remaining service life or projected wall thickness is accomplished using Engineering evaluations performed outside of the Erosion Module.

While no preventive actions are required by this program, activities such as monitoring of water chemistry to control pH and dissolved oxygen content can be effective in reducing FAC. Similarly, selecting FAC-resistant materials, or changing piping geometry for susceptible locations can be effective in reducing FAC. The aging management strategy related to FAC emphasizes a preference for design improvement over simple management of wall thinning.

The *Flow-Accelerated Corrosion* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *Flow-Accelerated Corrosion* program is an existing program that, following enhancement, will be consistent, with NUREG-2191, Section XI.M17, Flow-Accelerated Corrosion.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Scope of Program (Element 1) and Detection of Aging Effects (Element 4)

1. An Engineering evaluation will be performed for systems that have been excluded from FAC monitoring activities due to no flow, or infrequently used lines with a total operating and testing time that is less than 2% of the plant operating time during the first period of extended operation. The purpose of the Engineering evaluation is to confirm the scope of components that will qualify for the exclusion being extended into the subsequent period of extended operation. The Engineering evaluation and subsequent modeling changes for tracking FAC monitoring activities will be completed prior to entering the subsequent period of extended operation.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Flow-Accelerated Corrosion* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 2012, during the Spring 2012 Unit 1 refueling outage, a degraded elbow was identified on a small-bore low pressure steam pipe. The degraded elbow was replaced using chrome-moly during the 2012 outage. Scope expansion was required, and eight additional components were inspected. No additional degradation was noted.
2. In September 2013, during the Fall 2013 Unit 1 refueling outage, three components on a high pressure steam line were found to have wall thickness above code minimum wall thickness. However, those components did not have remaining wall thickness that complied with FAC program requirement to be at least 75% of nominal for small-bore piping operating above 500 psi. The three components were replaced during the Fall 2013 refueling outage using chrome-moly.

3. In March 2016, during the Spring 2016 Unit 2 refueling outage, an elbow on a 2-inch low-pressure pipe on a feedwater heater drain pump was scheduled for inspection. Prior to the inspection, the pump was removed and shipped offsite for repair with the elbow attached. The elbow was one of two remaining carbon components on the 2-inch line. Based on inspections of similar carbon components on the opposite train heater drain pump, the elbow was identified as needing to be replaced within five years using chrome-moly. The replacement of the elbow was completed during the Spring 2016 refueling outage.
4. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion was reached that no performance deficiencies or learning opportunities were identified for the Flow Accelerated Corrosion AMA (UFSAR Section 18.2.16).
5. In July 2016, a review by the Engineer responsible for the Flow Accelerated Corrosion AMA (UFSAR Section 18.2.16) found that components dispositioned as “No Further Inspections” (NFI) for the first 40-year operating period had not been formally re-evaluated to determine whether they required additional inspections during the extended license period. As such, there were likely components that were previously dispositioned as NFI that would now require further inspections to reach the licensed 60 years of operation. The importance of identifying these missed components is further escalated with the advent of the Subsequent License Renewal process for 80-year plant life. NFI components were included in the FAC Manager data migration updates for Units 1 and 2 through 80 years of operation. The data migrations included establishing a Next Scheduled Inspection (NSI) outage for each component.
6. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal aging management programs was conducted to confirm the following:
    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.
7. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the Flow Accelerated Corrosion AMA (UFSAR Section 18.2.16).

8. In April 2019, an effectiveness review was performed on the Flow Accelerated Corrosion AMA (UFSAR Section 18.2.16) that includes inspections for wall thinning in susceptible components. The AMA was evaluated against the performance criteria identified in NEI 14-12, “Aging Management Program Effectiveness”. No gaps were identified by the effectiveness review related to Flow Accelerated Corrosion AMA.

<u>Erosion Operating Experience</u>

9. In March 2010, during the Unit 2 refueling outage, a UT examination was performed on a 2-inch piping component on a 6-inch condenser header and found to have a wall thickness below the programmatic minimum value. Engineering evaluated two additional condenser headers scheduled for replacement in 2011 to determine whether the current inspection/replacement schedule would be appropriate. For Unit 1, condenser headers were previously inspected with an appropriate re-inspection interval. However, since some of the thinning in the condenser headers could have been due to liquid impingement and the replacement material was not resistant to liquid impingement, the three condenser headers previously replaced were assigned a re-inspection interval in CHECWORKS-SFA. Similarly for Unit 2, two condenser headers previously replaced were assigned a re-inspection interval in CHECWORKS-SFA.
10. In March 2018, during the Unit 1 refueling outage, while performing scheduled maintenance on a check valve in the secondary drains system, pitting was identified on the inside of the check valve body. The presence of pitting was an indication of possible erosion. The pitting resulted in a remaining wall thickness that was at the minimum allowable value. Corrective action was taken during the same refueling outage to perform weld repairs on the affected areas of the check valve body.

The above examples of operating experience provide objective evidence that the *Flow-Accelerated Corrosion* program includes activities to (a) identify susceptible piping systems and components; (b) develop FAC predictive models to reflect component geometries, materials, and operating parameters; (c) perform analyses of FAC models and, with consideration of operating experience, select a sample of components for inspection; (d) inspect components; (e) evaluate inspection data to determine the need for inspection sample expansion, repairs, or replacements, and to schedule future inspections; and (f) incorporate inspection data to refine FAC modeling. Additionally the *Flow-Accelerated Corrosion* program includes activities to manage wall thinning caused by flow-accelerated corrosion, as well as wall thinning due to erosion mechanisms. Occurrences identified under the *Flow-Accelerated Corrosion* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Flow-Accelerated Corrosion* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Flow-Accelerated Corrosion* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.9 Bolting Integrity

Program Description

The *Bolting Integrity* program is an existing condition monitoring program that manages aging by performing periodic visual inspections for indications of cracking, loss of material due to general, pitting and crevice corrosion, microbiologically influenced corrosion, wear, and loss of preload as evidenced by leakage for safety-related and nonsafety-related closure bolting on pressure retaining components within the scope of subsequent license renewal.

The preventive actions associated with this AMP include proper selection of replacement bolting material; the use of appropriate lubricants and sealants is consistent with the guidelines of EPRI Report 1015336, "Nuclear Maintenance Application Center: Bolted Joint Fundamentals," and EPRI Report 1015337, "Nuclear Maintenance Application Center: Assembling Gasketed Flanged Bolted Joints," along with additional recommendations from NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation of Failure in Nuclear Power Plants"; consideration of minimum specified yield strength when procuring bolting material; 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 consistent with guidance in EPRI documents, manufacturer recommendations, or engineering evaluation. These actions preclude loss of preload, loss of material, and cracking.

The *Bolting Integrity* program includes the following additional considerations from NUREG-1339:

- Visual examinations are performed in accordance with the *Boric Acid Corrosion* program (B2.1.4) to detect degradation of pressure boundary bolting caused by boric acid leakage.
- Visual and volumetric examinations are performed in accordance with the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1) to detect degradation of pressure boundary bolting due to stress corrosion cracking.

Guidance from EPRI Report 1015336 (Table 4-9) is included in the Bolting Integrity program, as indicated by the following tasks performed by the program:

- Examine all surface areas, especially the thread root area, for evidence of corrosion, cracking, galling, pitting, and mechanical damage.
- Inspect assemblies for proper thread engagement, correct size, proper lubricant and torque values during maintenance, where specified.
- Examine code material requirements, bolt and nut markings, and material identification.

Recommendations from EPRI Report 1015337 are followed for assembling bolted connections. Preventive measures to preclude or minimize cracking and loss of preload include proper selections of bolting material and lubricant, and proper application of preload.

The program activities provide for aging management of closure bolting on pressure-retaining components within the scope of subsequent license renewal. The program includes periodic inspection, at least once per refueling cycle, of closure bolting on pressure-retaining components for indication of loss of preload, cracking, and loss of material due to corrosion. The program also credits visual inspection of pressure-retaining bolted joints in ASME Class 1, 2, and 3 systems for leakage and age-related degradation during system pressure tests performed in accordance with ASME Code, Section XI. In addition, the Bolting Integrity program credits volumetric, surface, and visual inspections of ASME Section XI Class 1, 2, and 3 bolts, nuts, washers, and other associated bolting components performed in accordance with ASME Code, Section XI, Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1. The integrity of ASME and non-ASME pressure-retaining bolted joints which contain fluids such as water, oil, or steam is assessed by detection of visible leakage, evidence of past leakage, or other age-related degradation during walkdowns and maintenance activities. Conditions such as: degraded bolts, nuts and threads; active leakage; high noise levels; loose or missing bolts and nuts; evidence of past leakage; damaged insulation; discoloration; or other age-related degradation are entered into the corrective action program where the condition is evaluated.

There is no high-strength bolting (i.e., pressure boundary bolting with actual yield strength greater than 150 kilo-pounds per square inch) or bolts with unknown yield strength within the scope of the Bolting Integrity program, therefore sample based volumetric inspection of closure bolting greater than 2 inches in diameter to detect indications of cracking is not applicable.

The following three categories of closure bolting may preclude detection of joint degradation during normal system walkdowns and include closure bolting located in submerged environments, closure bolting for systems containing air or gas for which leakage is difficult to detect, and closure bolting for systems not normally pressurized. Closure bolting for each of the three categories will be visually inspected for loss of material during maintenance activities. Bolt heads will be inspected when made accessible, and bolt threads inspected if joints are disassembled.

- Submerged portions of piping systems include pump casings and discharge columns for the service water pumps, service water screen wash pumps, circulating water screen wash pumps, motor-driven and diesel-driven fire protection pumps, fire protection pressure maintenance pump, inside and outside recirculation spray pumps, low head safety injection pumps and various sump pumps. Also included are portions of the low head safety injection suction headers, recirculation spray suction headers, cavity seal ring, and fuel transfer gate valves. In each 10-year period during the subsequent period of extended operation, for each unit, a representative sample of bolt heads and threads is inspected up to a maximum of 19 bolts for each material and environment combination. If opportunistic maintenance activities will not provide access to 20% of the population (for a material/environment combination) up to a maximum of 19 bolt heads and threads over a 10-year period, then periodic pump vibration measurements are taken and trended.

- Air or gas systems include instrument air, primary and secondary gas supply, service air, emergency diesel generator (starting air), alternate AC (starting air), safety injection (nitrogen), and fire protection (halon and carbon dioxide). For air or gas systems, inspections are performed consistent with that of submerged closure bolting. In each 10-year period during the subsequent period of extended operation, for each unit, a representative sample of bolt heads and threads is inspected up to a maximum of 19 bolts for each material and environment combination. If opportunistic maintenance activities will not provide access to 20% of the population (for a material/environment combination) up to a maximum of 19 bolt heads and threads over a 10-year period, then soap bubble testing will be performed.
- Piping systems having a pressure boundary or leakage boundary intended function but not normally pressurized are identified with an “air - indoor uncontrolled” internal environment (e.g., recirculation spray system piping and associated spray headers, quench spray system piping and associated spray headers, and service water system piping to and from the recirculation spray heat exchangers). The atmospheric vent piping for other systems having a pressure boundary or leakage boundary intended function would also be included in this category. For this category of bolting, the torque of the bolting will be checked to the extent that the closure bolting is not loose. In each 10-year period during the subsequent period of extended operation, for each unit, a representative sample of bolt heads and threads is inspected up to a maximum of 19 bolts for each material and environment combination.

The maximum sample size of 19 is based on a two-unit site. This reduced number of inspections is acceptable based on the following:

- Water chemistry requirements for the two units are identical, and the operating conditions are similar. Any deviations from established water chemistry guidelines are corrected promptly.
- The raw water used for the two units comes from the same source so the probability of differences in susceptibility to aging mechanisms such as microbiologically influenced corrosion is low.
- The “air - indoor, uncontrolled” and “air-outdoor” environments are identical for both units.
- Operating experience for the two units indicates no significant differences in aging effects for the integrity of pressure-retaining bolting.

For sampling-based inspections, 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, additional inspections are conducted if one of the inspections does not meet acceptance criteria. The number of increased inspections is determined in accordance with the Corrective Action Program; however, no fewer than five additional (or 20%, whichever is less) inspections of different components having the same material/environment combination are required for each inspection that does not meet the acceptance criterion. For the two-unit site, the additional inspections include inspections at the same unit, and at the opposite unit, for components having the same material and environment combination. The additional inspections are to be completed within the same 10-year inspection interval. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, sampling frequencies will be adjusted as determined by the Corrective Action Program.

Inspections and tests are performed by personnel qualified in accordance with procedures and programs to perform the specified task. Inspections within the scope of the ASME Code follow procedures consistent with the ASME Code. Non-ASME Code inspections follow procedures that include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1) includes inspections of closure bolting within the scope of ASME Code, Section XI, and supplements this *Bolting Integrity* program. The following aging management programs manage aging effects associated with safety-related and nonsafety-related structural bolting:

- *ASME Section XI, Subsection IWE* program (B2.1.29)
- *ASME Section XI, Subsection IWF* program (B2.1.31)
- *Structures Monitoring* program (B2.1.34)
- *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.35)
- *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program (B2.1.13)

NUREG-2191 Consistency

The *Bolting Integrity* program is an existing program that, following enhancement, will be consistent, with NUREG-2191, Section XI.M18, Bolting Integrity.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Detection of Aging Effects (Element 4)

1. Procedure(s) will be enhanced to:
    a. include inspections of pressure-retaining bolting in inaccessible areas when they become accessible by means such as excavation, dewatering, or shielding/barrier removal, and
    b. include a requirement during opportunistic maintenance activities to document the condition of bolt heads and threads.
2. Procedure(s) will be developed and/or revised to provide instructions for performing inspections of pressure boundary bolting for plant locations that preclude detection of joint leakage including bolting in submerged environments, bolting for air or gas systems, and bolting for piping systems not normally pressurized as follows:
    a. Submerged closure bolting is visually inspected for loss of material during maintenance activities. In this case, bolt heads are inspected when made accessible, and bolt threads are inspected when joints are disassembled. In each 10-year period during the subsequent period of extended operation, for each unit, a representative sample of bolt heads and threads is inspected up to a maximum of 19 bolts for each material and environment combination. If opportunistic maintenance activities will not provide access to 20% of the population (for a material/environment combination) up to a maximum of 19 bolt heads and threads over a 10-year period, then periodic pump vibration measurements are taken and trended.
    b. For air or gas systems, inspections are performed consistent with that of submerged closure bolting. Closure bolting for air or gas systems is visually inspected for loss of material during maintenance activities. In this case, bolt heads are visually inspected when made accessible, and bolt threads are visually inspected when joints are disassembled. In each 10-year period during the subsequent period of extended operation, for each unit, a representative sample of bolt heads and threads is inspected up to a maximum of 19 bolts for each material and environment combination. If opportunistic maintenance activities will not provide access to 20% of the population (for a material/environment combination) up to a maximum of 19 bolt heads and threads over a 10-year period, then soap bubble testing will be performed.

c. For piping systems not normally pressurized, the torque of the bolting will be checked to the extent that the closure bolting is not loose. In each 10-year period during the subsequent period of extended operation, for each unit, a representative sample of bolt heads and threads is inspected up to a maximum of 19 bolts for each material and environment combination.

Monitoring and Trending (Element 5); Acceptance Criteria (Element 6); Corrective Actions (Element 7)

3. Procedure(s) will be developed and/or revised to evaluate sampling-based inspections against plant-specific acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, sampling frequencies will be evaluated and adjusted as determined by the corrective action program. Bolting that is unsuitable for continued use will be replaced. 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, additional inspections will be conducted if one of the inspections does not meet acceptance criteria. The number of increased inspections is determined in accordance with the site's 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 and environment combination is inspected, whichever is less. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of inspections. Additional samples are inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections include inspections of components with the same material and environment combination for each unit and are completed within the 10-year inspection interval in which the original inspection was conducted.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Bolting Integrity* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In August 2012, the NRC issued Information Notice 2012-15 (IN 2012-15), “Use of Seal Cap Enclosures to Mitigate Leakage from Joints that Use A-286 Bolts,” to inform licensees of the potential issues associated with the installation of seal cap enclosures to mitigate leakage from A-286 bolted connections. An unintended consequence of installation of seal cap enclosures

was cracking due to the stress corrosion cracking resulting from submergence of Alloy A-286 (Grade 660) flange bolting in leaked primary coolant. Subsequent to issuance of IN 2012-15, the PWR Owners Group (PWROG) issued Letter OG-12-330 (Generic Guidance for Valves that have Seal Encapsulation Devices Installed). PWROG Letter OG-12-330 provides guidance related to IN 2012-15 and recommends that owners identify the population of ASME Class 1 and 2 NSSS bolted bonnet check valves employing encapsulation devices, document an examination plan for all valves left in service with encapsulation devices installed, and examine all encapsulation devices that will be left in service. Based on a plant review, it was determined that there are no valves at North Anna that have seal cap enclosures installed. Therefore, the recommendations of OG-12-330 have been addressed and no further actions were required in regard to the use of seal caps at North Anna.

2. In December 2014, an incorrect PM frequency was identified for performing bolt stretch verifications for the Unit 2 'B' reactor coolant pump (RCP). These verifications are needed to manage loss of preload of RCP flange closure bolting due to relaxation. Engineering reviewed the work history for RCP bolt stretching and verification for all RCPs. The required frequency of once every 4th refueling outage (R4) for bolt re-stretch and once every other refueling outage (R2) for bolt stretch verification were satisfied for all RCPs. All RCP bolt stretch verification preventive maintenance (PM) schedules were reviewed. The incorrect PM frequency for performing RCP bolt stretch verifications was returned to an R2 frequency. The result of this corrective action was to ensure bolt stretch verifications are performed such that the pressure boundary intended function is maintained for the reactor coolant pumps.

3. In July 2015, during performance of pump inspection and repair of the Unit 1 '1C' main feedwater pump, one of the 20 casing stud bolts failed during reassembly. One additional stud was found to be cracked based on volumetric (UT) examination performed. UT examinations were performed on three additional removed studs with no indications identified and the remaining 15 studs were examined in place with no indications identified. The cracking in the stud was identified as likely attributable to intergranular stress corrosion cracking (IGSCC). No chlorides or sulfur were detected along the fracture or the thread deposits during this analysis; however, copper was detected. The cause of the bolt stress corrosion cracking was most likely due to the existence of older thread lubricants that are no longer used. The evaluation of this event included a review of similar industry operating experience where main feedwater pump casing studs were found to be cracked during routine NDE testing. These cracks were also attributed to IGSCC. As a result of cracking in the '1C' main feedwater pump studs, an extent of condition review was performed on the studs for the other two Unit 1 main feedwater pumps and the three Unit 2 main feedwater pumps. Ultrasonic testing was performed on the casing studs for the remaining main feedwater pumps with satisfactory results and no indications noted.

4. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion was reached that no performance deficiencies or learning opportunities were identified for the General Condition Monitoring Activities AMA (UFSAR Section 18.2.9) related to components within the scope of the *Bolting Integrity* program for subsequent license renewal.
5. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.
6. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the General Condition Monitoring Activities AMA (UFSAR Section 18.2.9) related to components within the scope of the *Bolting Integrity* program for subsequent license renewal.
7. In March 2019, the flanged bypass elbow on the turbine for the Unit 2 turbine-driven auxiliary feedwater pump was found to be loose. The bypass elbow flange nuts that were found to be loose after the maintenance run were located on the upper area of the lower flange. The bolts were re-torqued. Mechanical maintenance procedures for both units were revised to add a “Peer Check” sign-off to the steps which torque the bypass elbow flange fasteners.
8. In April 2019, an effectiveness review was performed on the General Condition Monitoring Activities AMA (UFSAR Section 18.2.9). The AMA was evaluated against the performance criteria identified in NEI 14-12, “Aging Management Program Effectiveness. No gaps were identified by the effectiveness review related to components within the scope of the *Bolting Integrity* program for subsequent license renewal.

The above examples of operating experience provide objective evidence that the *Bolting Integrity* program includes activities to perform visual inspections for indications of cracking, loss of material and loss of preload for pressure-retaining closure bolting within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Bolting Integrity* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Bolting Integrity* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Bolting Integrity* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.10 Steam Generators

Program Description

The *Steam Generators* program does not include primary-side sleeves since these components are not used in the steam generators. The program uses volumetric inspections for the tubes, and visual inspections for the other primary-side and secondary-side components. The visual inspections of primary-side components are performed in accordance with the Degradation Assessment (DA) that is prepared as each steam generator is scheduled for examination.

The *Steam Generators* program utilizes industry endorsed guidance regarding tube inspections, evaluation and repair, and leakage monitoring techniques to ensure tube integrity of the steam generators. Aging is managed through assessment of potential degradation mechanisms, inspections, tube integrity assessments, plugging and repairs, primary-to-secondary leakage monitoring, maintenance of secondary side component integrity, primary-side and secondary-side water chemistry, and foreign material exclusion. Implementing procedures specify 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 Technical Specifications (TS).

Provisions in the *Steam Generators* program address reporting criteria, inspection scope and frequency, assessments, plugging criteria, and water chemistry monitoring to maintain consistency with established requirements. Those requirements appear in the following documents:

- Technical Specifications (and Technical Requirements Manual)
- Maintenance Rule (10 CFR 50.65)
- EPRI 3002007571, “Steam Generator Integrity Assessment Guidelines”
- EPRI 3002007572, “PWR Steam Generator Examination Guidelines”
- EPRI Technical Report TR1022832, “PWR Primary-to-Secondary Leak Guidelines”
- EPRI 3002007856, “Steam Generator In-Situ Pressure Test Guidelines.”

The EPRI guidelines provide a generic industry program to implement the expectations from NEI 97-06, Revision 3, “Steam Generator Program Guidelines.”

The original steam generators were replaced for Unit 1 in 1993 and for Unit 2 in 1995. The steam generator replacement projects involved replacing the lower section of each steam generator and refurbishing the upper section. The replacement steam generators incorporated Alloy 690 thermally-treated tubes to improve reliability and minimize aging.

The *Steam Generators* program includes plant-specific steam generator DAs that identify existing and potential degradation mechanisms and associated aging effects that could impact the integrity of the steam generators. The DA identifies qualified tube inspection techniques and defines the scope of inspections that are appropriate for the detection and characterization of those aging effects, which consist of cracking, loss of material (e.g., wall thinning), and reduction of heat transfer. As stated in the DA, U-tube and primary-side inspections are normally performed every third refueling outage for each steam generator, thus satisfying the guidance for inspections to be performed at least every 72 effective full power months or every third refueling outage, whichever results in more frequent inspections. The DA includes a review of applicable industry operating experience (OE) and plant-specific OE which has occurred since the previous DA was performed. The DA review determines the existence of any unaddressed mechanism that could adversely affect steam generator primary-side or secondary-side integrity, as well as the effects of any chemistry excursions or transients that could affect existing degradation mechanisms. An excursion of secondary chemistry could lead to fouling of heat transfer surfaces and a reduction of heat transfer thermal performance.

The DA indicates that primary-side inspections include video/visual examinations, specifically including:

- Tube plugs
- Tube-to-tubesheet welds
- Stub runner and divider plate
- Stub runner to divider plate weld
- Stub runner to tubesheet clad weld
- Divider plate-to-channel head clad weld
- Tubesheet cladding
- Closure ring welds
- Bottom of the bowl cladding

The analysis of the steam generator tube-to-tubesheet welds and the channel head design and loading provided by EPRI Technical Report 3002002850, “Steam Generator Management Program: Investigation of Crack Initiation and Propagation in the Steam Generator Channel Head Assembly” is applicable and bounding. A plant specific aging management program is not required for the primary-side channel head. The steam generator tubesheet is clad with Alloy 82, and the Alloy 690 thermally treated tubes are joined to the tubesheet with autogenous welds. General visual inspections of the tubesheet region looking for evidence of cracking (e.g., rust stains on the tubesheet cladding) are performed as part of this program.

The *Steam Generators* program includes preventive measures to mitigate aging related to corrosion phenomena through foreign material exclusion as a means to inhibit tube degradation due to wear. Identification of deposits on the secondary side of the steam generator, and the subsequent removal of sludge deposits help avoid tube degradation. Sludge mapping occurs when the steam generator is inspected, and inspections for remaining foreign material are performed after sludge lancing is completed. Sludge lancing, steam drum inspections, and feedring inspections typically are performed at least every third refueling outage. As an additional preventive measure, the *Water Chemistry* program (B2.1.2) monitors and controls reactor water chemistry and secondary water chemistry for the steam generators consistent with EPRI 3002000505, “PWR Primary Water Chemistry Guidelines,” and EPRI 3002010645, “PWR Secondary Water Chemistry Guidelines”.

The TS include the following requirements which have been incorporated in the *Steam Generators* program:

- Conducting condition monitoring assessments for each refueling outage during which steam generator tubes are inspected or plugged.
- Maintaining steam generator tube integrity by meeting performance criteria for tube structural integrity, accident-induced leakage, and operational leakage.
- Installing plugs in tubes found by inservice inspection to contain flaws with a depth equal to, or exceeding, 40% of the nominal tube wall thickness.
- Performing periodic inspections of steam generator tubes. Inspection scope, methods, and interval ensure that tube integrity is maintained until the next planned inspection.
- Monitoring primary-to-secondary leakage.
- Monitoring secondary water chemistry to ensure controls are in place to inhibit steam generator tube degradation.

Non-destructive examination techniques are used to inspect tubing materials in order to identify tubes that may need to be removed from service in accordance with the TS. The *Steam Generators* program utilizes volumetric examination techniques for the tubes, and visual examinations for other primary-side and secondary-side components. The *Steam Generators* program defines specific examination techniques, and describes criteria for the qualification of personnel, and for the acquisition and analysis of data. Assessment of tube integrity and plugging criteria of flawed tubes is in accordance with the TS and the *Steam Generators* program implementing procedures. Tube plugs with indications of aging are evaluated for corrective actions in accordance with the Corrective Action Program and the *Steam Generators* program.

Condition monitoring assessments are performed to determine whether structural and accident leakage criteria have been satisfied during the previous operating cycle(s). Operational assessments are performed after inspections are completed to verify that structural and leakage integrity will be maintained for the operating interval between inspections, which is selected in accordance with the TS and EPRI Steam Generator Integrity Assessment Guidelines. Comparison of the results of the condition monitoring assessment with the predictions of the previous operational assessment provides feedback for evaluation of the adequacy of the operational assessment and additional insights that can be incorporated into the next operational assessment. The condition monitoring, and performance monitoring methods, are effective in detecting the applicable aging effects, and the frequency of monitoring is adequate to prevent significant age-related degradation.

The *Steam Generators* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *Steam Generators* program is an existing program that is consistent with NUREG-2191, Section XI.M19, Steam Generators.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Steam Generators* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In March 2009, a foreign object was found in the Unit 1 'A' steam generator during a foreign object search and retrieval examination. The object was retrieved and the tubes in the vicinity of the foreign object were visually examined. No significant tube wall loss was identified and no further evaluation was required.

2. In September 2009, Regulatory Issue Summary 2009-04 (RIS 2009-04), “Steam Generator Tube Inspection Requirements,” provided guidance on the implementation of the steam generator inspection requirements. The Steam Generator Inspections AMA (UFSAR Section 18.2.18) was reviewed and found to be consistent with the interpretations provided in RIS 2009-04. No further action was needed.
3. In March 2010, foreign material was found in the Unit 2 'C' steam generator during the post sludge-lancing top-of-tubesheet inspection. The material was found to be weld slag, and was retrieved. Inspection of surrounding tubes noted no damage or marks on tubes. No further action was required.
4. In March 2010, a small metallic piece of material was found in the Unit 2 'A' steam generator during the post sludge-lancing top-of-tubesheet inspection. There were no indications of wear on the surrounding tubes. The piece of foreign material was removed. No further action was needed.
5. In April 2010, foreign material was noted in Unit 2 ‘B’ steam generator during the post sludge-lancing top-of-tubesheet inspection. Material was noted as wire-like, and it appeared the ends were embedded in a portion of the remaining sludge. The wire was sized less than 0.020 inch in diameter by less than 0.5 inch in length. The tubes adjacent to the wire, and ten surrounding tubes, were +Point examined and no tube degradation was identified. The exposed portion of the wire broke free during a retrieval attempt. An evaluation was provided in the Condition Monitoring and Operational Assessment document. Due to the small diameter, length, and minimal mass, the remaining portion of the wire was determined to not pose a threat to tube integrity.
6. In September 2011, foreign material was noted protruding from the hot leg end of a tube in the Unit 1 ‘A’ steam generator. An additional piece of foreign material was located in the hot leg bowl. An apparent cause evaluation stated that the presence of the foreign material was a breakdown of the Foreign Material Exclusion boundary for the reactor coolant system. The surface of the steam generator tubesheet did not show any evidence of impacts on the cladding or tube ends. No tube wear was observed in the tube containing the foreign material. Therefore, there was no evidence that the foreign material caused any damage to the steam generator or reactor coolant system. The foreign material was removed.
7. In September 2013, ultrasonic testing (UT) examination results for Unit 1 ‘A’ steam generator indicated wear in the vicinity of a J-tube nozzle. Additional UT examinations and visual inspections for the internal surfaces of the feedrings for all three steam generators resulted in repairs being planned for several J-tube nozzles during the following outage. An Engineering evaluation concluded that the affected J-tube nozzles were fully capable of performing their design basis function, and would maintain structural integrity for an additional 18-month cycle until the repairs could be performed.

8. In September 2013, during post sludge-lancing visual inspection of Unit 1 ‘A’ steam generator, a loose part was identified at the top of the tubesheet. The part appeared to be weld slag, and was removed. Eddy current testing for the two tubes that were in contact with the loose part determined there was no wall loss on either tube contacted by the loose part. Further eddy current examinations for the row of surrounding tubes did not identify any degradation. No further action was required.
9. In March 2016, a foreign object was identified by eddy current testing in a Unit 2 ‘C’ steam generator cold leg tube at the third tube support plate. Foreign object wear with a maximum wall loss of 33%, believed to be from the same foreign material, was identified on an adjacent cold leg tube. The location was inaccessible for foreign object retrieval. The two tubes were plugged at the cold leg and the hot leg, and were stabilized at the cold leg.
10. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.
11. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 during November and December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the Steam Generator Inspections AMA (UFSAR Section 18.2.18).
12. In October 2017, NSAL-12-1, “Steam Generator Channel Head Degradation”, was issued to describe degradation of the Steam Generator channel head cladding in a Westinghouse-designed steam generator. Recommended action from NSAL-12-1 was to perform a visual inspection to identify potential breaches in the cladding. No additional action was necessary since steam generator bowl scans of each channel head are performed during primary-side inspections.
13. In March 2018, foreign material was found on the internal surface of the feedring of Unit 1 ‘B’ steam generator. The piece of foreign material was removed, and was determined to be a backing ring used for initial welding and installation of the feedring. No damage was identified within the feedring. An inspection of the entire feedring was conducted and other backing rings and other materials were verified intact. Inspections were also performed within the feedrings for the 'A' and 'C' Steam Generators. Backing rings and other components were intact.

14. In April 2019, an effectiveness review was performed on the Steam Generator Inspections AMA (UFSAR Section 18.2.18). The AMA was evaluated against the performance criteria identified in NEI 14-12, "Aging Management Program Effectiveness." No gaps were identified by the effectiveness review.

The above examples of operating experience provide objective evidence that the *Steam Generators* program includes activities to perform volumetric and visual inspections to identify cracking, loss of material and reduction of heat transfer for primary-side components and secondary side components contained within the steam generator that are within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Steam Generators* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Steam Generators* program will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Steam Generators* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.11 Open-Cycle Cooling Water System

Program Description

The *Open-Cycle Cooling Water System* program is an existing preventive, mitigative, condition monitoring, and performance monitoring program that manages loss of material, reduction of heat transfer, flow blockage, and cracking of piping, piping components, and heat exchangers identified by the responses to NRC GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment" (ADAMS Accession No. ML20085H840). The program is comprised of the aging management aspects of the Virginia Electric and Power Company response to GL 89-13 and includes: (a) surveillance and control to reduce the incidence of flow blockage problems as a result of biofouling, (b) tests to verify heat transfer of safety-related heat exchangers, (c) routine inspection and maintenance so that loss of material, corrosion, erosion, cracking, fouling, and biofouling cannot degrade the performance of systems serviced by the open-cycle cooling water system. Additionally, recurring internal corrosion (RIC) is addressed in the Corrective Action Program through design modifications that have replaced materials more susceptible to degradation in raw water with materials that are less susceptible to degradation in raw water. This program includes enhancements to the guidance in NRC GL 89-13 that address operating experience (OE) to provide reasonable assurance that aging effects are adequately managed.

The open-cycle cooling water system includes those systems that transfer heat from safety-related systems, structures, and components to the ultimate heat sink as defined in GL 89-13. North Anna Power Station uses a fresh-water lake (North Anna reservoir) for circulating water and make-up to the service water reservoir. The North Anna reservoir and service water reservoir are the two independent sources of water that form the ultimate heat sink for North Anna Power Station.

The guidelines of GL 89-13 are utilized for the surveillance and control of biofouling for the open-cycle cooling water system. Procedures provide instruction and control for chemical and biocide injection. Periodic sampling procedures monitor system chemical addition concentrations. In addition, periodic flushing, cleaning and/or inspections are performed for the presence of biofouling.

Periodic heat transfer testing, visual inspection and cleaning of safety-related heat exchangers with a heat transfer intended function is performed in accordance with the site commitments to GL 89-13 to verify heat transfer capabilities.

Titanium tubes, stainless steel tubes and titanium tubesheets are cleaned with brushes in combination with as found visual inspection of the tubesheet for corrosion and discoloration due to dealloying. Eddy current testing for tube denting, pits and cracks is performed every 24 years for titanium tubes and 12 years for stainless steel. Inspection, cleaning and plugging of tubes is performed every four years for titanium tubes and three years for stainless steel to minimize pit/crack initiation points. Due to their small size and cleaning/inspection intervals, the charging pump and speed increaser lube oil coolers are on a time-based replacement verses eddy current testing.

Safety-related piping segments are examined (i.e., ultrasonic testing) periodically (currently 24 months) to ensure there is no significant loss of material, which could cause a loss of intended function.

Routine inspections and maintenance ensure corrosion, erosion, sediment deposition (silting), and biofouling do not degrade the performance of safety-related systems serviced by the open-cycle cooling water system. The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) manages the aging effects of internal surface coatings.

Aging effects associated with elastomers and flexible polymeric components in the open-cycle cooling water system are managed by the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program (B2.1.25).

The *Buried and Underground Piping and Tanks* program (B2.1.27) manages the aging effects of external surfaces of buried and underground piping and components. The external surface of the above ground raw water piping and heat exchangers is managed by the *External Surfaces Monitoring of Mechanical Components* program (B2.1.23). The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) will manage the aging effects of internal surface coatings.

The *Open-Cycle Cooling Water System* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *Open-Cycle Cooling Water System* program is an existing program that is consistent, with exception, to NUREG-2191, Section XI.M20, Open-Cycle Cooling Water System.

Exception Summary

The following program element is affected:

Detection of Aging Effects (Element 4)

1. Section XI.M20 of NUREG-2191, Open-Cycle Cooling Water, indicates that testing intervals can be adjusted to provide assurance that equipment will perform the intended function between test intervals, but should not exceed five years. The *Open-Cycle Cooling Water System* program takes exception to the NUREG-2191 requirement to perform testing of the recirculation spray heat exchangers (RSHXs) at an interval not to exceed five years.

Justification for Exception:

As described in the plant responses to GL 89-13 (ADAMS Accession No. ML18153C095), heat transfer performance testing of the RSHXs is not performed due to system configuration that would require significant design modifications to support such testing. The RSHXs are visually inspected to confirm the absence of indications of degradation. To further reduce the potential for degradation, the internal environment of the RSHXs and the portion of the connected piping that cannot be isolated from the RSHXs is maintained in dry layup (i.e., maintained in an air environment). The open-cycle cooling water side of the RSHXs are periodically flow tested and visually inspected.

The response to GL 89-13 (ADAMS Accession No. ML18153C611) indicated that the RSHXs would be flow tested every refueling outage with no inspections. Testing and any inspection intervals would be modified based on the results of future testing. Initial eddy current testing was established on a four cycle (six years) basis in 2010. Based on the results of further testing, the RSHXs are currently flow tested every 18 months with visual inspection and eddy current testing at an interval of 12 refueling outages (i.e., 18 years).

The change in frequency from no required inspections to once every 12 refueling outages for RSHX visual inspection and eddy current testing was evaluated by Engineering. The evaluation included a review of prior operating experience (flow testing and visual inspection results). Flow test results documented between 2009 and 2019 were reviewed. The test results identified little, or no blockage and all test were completed satisfactorily. RSHX service water inlet and outlet pipe cleaning and inspection are performed on a frequency consistent with RSHX flow testing. A review of prior piping inspection results between 2007 and 2017 showed the piping to be in satisfactory condition. Although coating defects and areas of corrosion were identified during the piping inspections, the RSHXs were determined to be capable of performing their intended function. Required coating and weld repairs were entered in the Corrective Action Program.

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Open-Cycle Cooling Water System* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In 2005 to 2009, the service water system spray array piping was replaced. Due to multiple leaks from 1998 to 2004 a design change was implemented to replace all the service water spray array piping. A materials evaluation determined the leaks occurred due to localized pitting corrosion in the carbon steel piping and the long-term corrective action was to replace

the spray arrays. Spray array replacements began in 2005 and were completed in 2009. Later, an Engineering evaluation determined the combination of spray array piping material (carbon steel with no internal coating) and the method of operation (spray arrays being placed in and out of service due to environmental and plant conditions) left the bare carbon steel in a wetted condition for extended periods of time which was conducive to the formation of MIC. The continuous drain lines were identified to be the cause for potential increased wear on the piping and higher than expected suspended solids in the water. A subsequent design change was developed in 2015 to provide for changing the drainpipe configuration by removing the previously installed 90-degree elbow and returning to the original straight down drain design which would limit the wear on system piping and reduce the suspended particulates in the water. Operations periodic tests were performed to visually inspect the service water spray arrays for through wall leakage, number of spray nozzles that were flowing and drains that were flowing. A review of test data from 2011 to 2020 did not identify any through wall leaks or spray nozzles that were not flowing. The number of drains full flowing was cyclic and attributed to scheduling of the annual spray array nozzle/drain cleaning and flushing preventive maintenance. There were no tests resulting in a spray array being declared inoperable. As a result of service water spray array pipe wall thickness monitoring that indicated some locations were approaching pipe minimum wall thicknesses, eight segments of 18-inch service water spray array piping were replaced in 2015.

2. In November 2008, during performance of the Operations service water reservoir components inspection test, three clogged drains were identified on a Unit 1 service water spray array. This periodic test, performed at least every three months for functional testing of the service water reservoir spray array grids, verifies sufficient spray arrays on each header are operable, identifies clogged drains and inspects spray array piping for through wall leaks. A condition report is submitted for any pipe leaks, clogged drains or spray nozzles and repairs are required to be performed within six months in accordance with the procedure. The clogged drains were subsequently cleared in December 2008.

3. In November 2008, during an Engineering as found inspection of the Unit 2 'C' charging pump lube oil cooler, a heavy layer of green slime was discovered on the tubesheet third pass return and inlet to the fourth pass. There was no indication of any slime in the Unit 1 'B' charging pump lube oil cooler which was inspected one month after the slime was identified on the Unit 2 'C' cooler which had been in-service for three years. The other heat exchanger had an 18-month inspection frequency and did not exhibit the algae growth. Engineering was unable to classify the algae type after completing a visual inspection. The Unit 2 'B' component cooling heat exchanger was inspected in January 2009 after being in service for three years. The channel head and tube sheet had a heavy layer of algae. The chemistry for the service water reservoir was undergoing a change in the chemicals being used when the algae was identified. Factors associated with fouling such as turbidity, pH, and biocide concentration

were being closely monitored during this transition to ensure no adverse conditions were created.

4. In January 2009, corrosion rates on the service water in-line coupons exceeded chemistry cooling water procedure action levels. The corrosion rate on the component cooling heat exchanger outlet was 7.5 mpy (mils per year) with the action level value being > 5 mpy. Corrosion rates on the heat exchanger inlet were 5.8 mpy. Chemical additives are used to mitigate and prevent corrosion of piping. A review of the chemistry data and operation of the system identified a decrease in pH of the service water system. This was attributed to a decrease in chemical corrosion inhibitor concentrations, improved algae control and reduced flow due to throttling of the system which resulted in increased corrosion rates. A new chemical treatment program was implemented in February 2009 which does not use molybdate as its primary chemical. The new program contains a buffer additive that is designed to increase the water pH. Following the first addition of the new treatment the pH showed a significant increase. Based on technical input from the chemical additive company, the chemistry procedure was enhanced to include service water operating pH range recommendations.

5. In September 2009, during the performance of an Engineering periodic test procedure for Generic Letter 89-13, “Service Water System Testing Requirements Coordination,” it was identified a repeat non-conformance existed during the review period. The non-conformance consisted of leaks on five different service water lines. Engineering review of both service water spray arrays determined them to be fully functional. A design change replaced the 2B2 spray array header in November 2009 and 1A1 was replaced in August 2009. A pin hole leak developed on the 4-inch service water supply line to the Unit 2 'A' control room chiller. The investigation of the Unit 2 'A’ control room chiller leak determined the line had extensive tuberculation or nodules, most likely caused by the amount of time water is stagnant in the line. Each unit has three chillers and the in-service unit is rotated monthly. Limited ultrasonic testing had been performed but did not identify the thin wall area prior to failure. An inactive MIC leak was identified downstream of the 'A' instrument air compressor on a tee joint to a line drain valve. The Unit 2 'A’ control room chiller and 'A' instrument air compressor piping was repaired.

6. In August 2010, four of six end bells on the instrument air compressor heat exchangers required repair or replacement due to pitting. It was determined one end bell flange could be machined and three others needed replacement. Based on the as-found condition and previous work order history, MIC was determined to be the cause of the flange pitting. A new gasket material was approved to prevent service water leakage onto the flange faces.

7. In November 2010, the Unit 1 'C' charging pump gearbox cooler service water outlet isolation valve developed a through-wall leak at the upstream socket weld. The leak rate was

approximately three drops/hour. Both service water trains were subsequently declared inoperable. Visual inspection and subsequent metallurgical testing determined the failure mechanism at the socket weld to be MIC. The section of pipe was cut out and replaced and returned to service. A design change replaced the stainless steel piping in the service water system with AL-6XN in selected sections of service water piping. Piping to the charging pumps that could be isolated was not upgraded to AL-6XN at the time. Design changes have been developed and are scheduled for future implementation to replace the stainless-steel piping with AL-6XN inside all the charging pump cubicles.

8. In August 2012, during the performance of the service water MIC leakage inspection test for Unit 1 and 2, MIC was observed in a socket weld on the Unit 1 'A' charging pump heat exchanger service water return line. The MIC indication was black and moist in consistency and located within the weld material. Based on the leak location, weld flaw characterization was not possible, and operations immediately isolated the leak. The section of piping was replaced with AL-6XN that is less susceptible to MIC.

9. In May 2016, during scheduled eddy current testing on the Unit 2 'A' charging pump gearbox oil cooler, greater than 40% pitting depth on nine of 40 tubes was identified. This was the first time eddy current test of this oil cooler and the frequency was set at six years. Prior to this eddy current test, only visual inspections and cleaning were performed. As a result of the pitting, the oil cooler was replaced. Based on eddy current results, out of service time, scope of work, age of the coolers and overall cost, engineering determined the charging pump gearbox and pump coolers should be changed to a 9-year replacement frequency and elimination of eddy current testing. These coolers are cleaned and inspected on a 3-year frequency to meet the maintenance and inspection commitment to GL 89-13. Eddy Current testing requirements are determined by the heat exchanger program and are not part of the GL 89-13 requirements or commitments.

10. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.

11. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the service water system inspection AMA UFSAR Section 18.2.17. The next Ultimate Heat Sink inspection is scheduled to be performed in 2020.
12. In April 2019, an effectiveness review was performed on the service water system AMA (UFSAR Section 18.2.17). The AMA was evaluated against the performance criteria identified in NEI 14-12, “Aging Management Program Effectiveness”. No gaps were identified by the effectiveness review.

Recurring Internal Corrosion (RIC)

Recurring internal corrosion has occurred in the service water system from 2009 to 2019 due to microbiologically influenced corrosion (MIC) and pitting in uncoated steel and stainless-steel piping with specific corrective actions implemented for the spray array piping, charging pump cooler piping, and main control room chiller piping.

Spray array piping: In 2005 to 2009, the service water system spray array carbon steel piping was replaced as a corrective action for multiple leaks identified from 1998 to 2004. A subsequent design change was developed to provide for changing the drainpipe configuration by removing the previously installed 90-degree elbow and returning to the original straight down drain design which would limit the wear on system piping and reduce the suspended particulates in the water.

Charging pump cooler piping: To eliminate the piping leaks with the charging pump and speed increaser oil cooler supply and return lines a design change replaced MIC susceptible stainless-steel piping outside of the pump cubicles with ALX-6N. Since this pipe replacement project was completed no additional leaks have occurred in those sections of ALX-6N pipe. To further mitigate potential future MIC related stainless steel pipe failures, design changes were developed to replace stainless steel pipe with ALX-6N inside the charging pump cubicles for the service water supply and return lines for the pump and speed increaser oil coolers. One pump’s piping has been replaced and the remainder are scheduled.

Main control room chiller piping: Continued loss of material and leaks on the Control Room chiller carbon steel service water lines has been identified and is being trended by Engineering. To supplement the normal ultrasonic testing (UT) examination data, additional UT examinations are scheduled to be performed on the Unit 1 and Unit 2 service water lines. This additional UT examination data will be used to evaluate the piping wall thickness and determine future corrective actions.

Periodic service water system piping inspections, spray array flow testing, and piping wall thickness measurements are performed to identify piping degradation prior to loss of system intended function. In addition to corrective actions associated with charging pump cooler piping replacements and trending of Control Room chiller piping to address instances of RIC, Low Frequency Electromagnetic Technique (LFET) or a similar technique will be used for screening 100 feet of piping during each refueling cycle to detect changes in the wall thickness of the pipe. LFET screening or a similar technique will also be performed on accessible piping during periodic inspections. Thinned areas found during the LFET scan will be followed-up with wall thickness examinations to ensure aging effects are managed and that wall thickness is within acceptable limits. In addition to the wall thickness examination, opportunistic visual inspections of the service water system will be performed whenever the service water system is opened for maintenance.

See the *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) for recurring internal corrosion operating experience for loss of material in coated service water system carbon steel piping.

The above examples of operating experience provide objective evidence that the *Open-Cycle Cooling Water System* program includes activities to perform surveillance, test, maintenance and inspections to identify loss of material, reduction of heat transfer, flow blockage, and cracking of piping, piping components, and heat exchangers that are identified by the Virginia Electric and Power Company responses to NRC GL 89-13, and to initiate corrective actions. Occurrences identified under the *Open-Cycle Cooling Water System* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Open-Cycle Cooling Water System* program will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Open-Cycle Cooling Water System* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.12 Closed Treated Water Systems

Program Description

The *Closed Treated Water Systems* program is an existing condition monitoring and mitigation program that manages the aging effects of cracking, loss of material, and reduction of heat transfer. The program consists of: (a) water treatment, including the use of corrosion inhibitors, to modify the chemical composition of the water such that the effects of corrosion 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. The program uses as applicable, EPRI Report 3002000590, “Closed Cooling Water Chemistry Guideline”. Microbiological testing is performed as a diagnostic chemistry parameter for selected system water treatments.

The *Closed Treated Water Systems* program activities are implemented through procedures. Mitigative activities include utilizing molybdate-based, chromate-based, or glycol-based chemistry controls to minimize the age-related degradation of components exposed to a closed treated water environment. The chilled water system uses pure water corrosion control, but can also be aligned to service water, which contains a molybdate-based corrosion inhibitor. The performance of sample analyses assures water chemistry parameters are maintained within the goal ranges specified by procedures based on EPRI Report 3002000590. Monitoring of water chemistry parameters also assures contaminants are kept below applicable limits to minimize corrosion. Condition monitoring activities provide for periodic and opportunistic visual inspections whenever the system boundary is opened. A representative sample of components is selected based on the likelihood of loss of material, cracking, or reduction of heat transfer and inspected at an interval not to exceed once in ten years. At a minimum, in each 10-year period during the subsequent period of extended operation, a representative sample of 20% of the population (defined as components having the same material, water treatment program, and aging effect combination) or a maximum of nineteen components per population for each unit will be inspected. At least 20% of the surface area will be inspected unless the component is measured in linear feet, such as piping. For piping, inspecting a one-foot axial length section is considered one inspection. Any combination of one-foot sections of piping and components can be used to meet the recommended extent of nineteen inspections.

Where the sample size is not based on the percentage of the population, the total number of inspections is reduced to nineteen components per population for each unit. The reduced total number of inspections is acceptable because the operating conditions and history at each unit are sufficiently similar (e.g., flowrate, chemistry, temperature, excursions) such that aging effects are not occurring differently between the units. Both use the same corrosion inhibitors and chemistry methods for closed treated water systems. Past power uprates were implemented for both units at approximately the same time. Operating experience for each unit demonstrates no significant difference in aging effects of closed treated water systems between the units.

Inspections will focus on the bounding or lead components most susceptible to aging due to time in service, and severity of operating conditions.

Heat transfer capability of heat exchanger surfaces is evaluated by performing as-found visual inspections that assess surface cleanliness.

If any inspections do not meet the acceptance criteria, additional inspections will be conducted, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes.

The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted. Inspections and tests are performed by personnel qualified in accordance with procedures and programs to perform the specified task. Inspections within the scope of the ASME Code follow procedures consistent with the ASME Code. Non-ASME Code inspection procedures include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

Potassium chromate is added to the water in the neutron shield system as a corrosion inhibitor. The potassium chromate is initially very corrosive when in contact with carbon steel. This corrosion provides a quickly formed, thick oxide layer on the inside surfaces of the tank which precludes further corrosion. At the levels recommended for corrosion control, chromate is also an effective microbiological control agent.

The *Closed Treated Water Systems* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *Closed Treated Water Systems* program is an existing program that, following enhancement, will be consistent, with NUREG-2191, Section XI.M21A, Closed Treated Water Systems as modified by SLR-ISG-Mechanical-2020-XX, Updated Aging Management Criteria for Mechanical Portions of the Subsequent License Renewal Guidance.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Detection of Aging Effects (Element 4)

1. A new procedure will be developed to specify that in each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed for the various sample populations (each material, water treatment program, and aging effect combination). If opportunistic inspections will not fulfill the minimum number of inspections by the end of each 10-year period, the program owner will initiate work orders as necessary to request additional inspections. A representative sample of 20% of the population (defined as components having the same material, water treatment program, and aging effect combination) or a maximum of nineteen components per population at each unit will be inspected. The new procedure will specify that the inspections focus on the bounding or lead components most susceptible to aging due to time in service, and severity of operating conditions.

Monitoring and Trending (Element 5)

2. A new procedure will be developed to specify that, where practical, the rate of any degradation is evaluated and projected until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The sampling bases (e.g., selection, size, frequency) will be adjusted as necessary based on the projection.

Corrective Actions (Element 7)

3. A new procedure will be developed to specify that additional inspections will be performed if any inspections do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Closed Treated Water Systems* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In March 2009, the chilled water system exceeded the procedural specification limit for conductivity. The increase in conductivity was expected, due to realignment of the Containment recirculation air coolers from service water to chilled water. Specifically, the Containment recirculation air cooler design allows the alignment of cooling water from either source, and when realigned to chilled water, service water as the back-up source to the chilled water system, allowed an increase in cooling water conductivity. Chilled water system blowdown was maximized to reduce the conductivity. Conductivity did not return to specification limits within thirty days. EPRI guidance and plant procedure require performing an Engineering evaluation to assess the long-term reliability of the system if a specification is exceeded for thirty days. Consistent with EPRI guidance and plant procedure, Engineering developed a materials evaluation to examine the corrosion susceptibility of chilled water system materials due to periodic out-of-specification chemistry from service water introduction. The report documented nondestructive ultrasonic testing (UT) examination and visual inspections performed by Engineering in various locations of the chilled water system to develop a baseline for the condition of materials in the system. The UT examination results revealed minimal wall loss, and the visual inspections indicated very little corrosion. Based on literature review and system inspection data, the report concluded that the corrosion rates in the chilled water system are expected to be low, even with periodic out-of-specification conditions. Conductivity returned to within specification in April 2009.

2. In 2010 through 2020, the iron concentration for the Unit 1 and Unit 2 neutron shield tanks has been analyzed and trended, when it was first specified by the plant sampling procedure in 2010. Iron is sampled as a diagnostic parameter and does not have a specified operating range. Iron concentration has been less than 0.05 ppm for both units since 2010.

   The chromate concentration since 2010 has ranged between 2098 and 3142 ppm for the Unit 1 tank and between 219 and 251 ppm for the Unit 2 tank. The normal operating range for chromate specified by procedure is 150 to 500 ppm. The higher concentration of chromates provides additional corrosion protection in the presence of high concentration of sodium chloride and sodium sulfate. The reason for the upper limit for chromates is due to the degradation of carbon pump seals caused by high chromate levels above 500 ppm. The neutron shield pumps do not have carbon seals. The system operates under natural circulation. The pumps are not operated. The high concentration of chromate in the Unit 1 neutron shield tank is acceptable.

3. In July and August 2016, several increases in coolant level for an emergency diesel generator (EDG) were noted in the coolant expansion tank. A condition report was initiated to document the occurrence and investigate the cause. Microbiological growth within the coolant system would cause a level increase due to off-gassing of the aerobic bacteria. The gas bubbles created by the bacteria would get trapped within piping due to decreased coolant flow rates while the engine is in standby. These trapped bubbles manifest as a tank level increase because they displace coolant. This phenomenon had previously been observed on the other engines.

   In mid-August, leakage of coolant was noted at '1H' EDG. The location was speculated to be the coolant water expansion tank fill cap. Another condition report was written. Microbiological testing confirmed active microbiological activity within the EDG coolant water.

   An evaluation was conducted by the laboratory vendor that determined the most likely cause was attributed to denitrifying bacteria present in the coolant that consume nitrogen-containing compounds in the coolant to produce nitrogen gas.

   Engineering evaluated other coolant options that would not provide a food source for microorganisms. As a result, use of a glycol coolant formulation with phosphate and tolyltriazole corrosion inhibitors was approved and use of the nitrite-based inhibitor was discontinued. Since change-out to the new coolant formulation, no increase has been noted in the coolant level in the EDG cooling water expansion tank.

4. In September 2016, during a Unit 1 outage, the '1A' neutron shield tank cooling water pump demonstrated seal leakage when the pump was placed in service to obtain a sample for chemical analysis. The seal leakage was determined to be attributed to abnormal seal wear and a work order was initiated to repair the seal. The work order is scheduled to be completed in an upcoming refueling outage. This operating experience is considered an isolated incident, since no other occurrences of seal leakage have been noted in the last ten years, and no information is available for the one instance of seal leakage that was determined to be attributed to abnormal seal wear.

5. December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

6. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the Chemistry Control Program for Primary Systems AMA (UFSAR Section 18.2.4) or Chemistry Control Program for Secondary Systems AMA (UFSAR Section 18.2.5) related to Closed Treated Water Systems.

7. In January 2018, a vendor analysis of a Unit 2 emergency diesel generator cooling water sample indicated that phosphate concentration had exceeded a station procedural limit but was still within the upper limit recommended by the vendor. Chemistry supervision was notified, another sample was obtained, and a condition report was written.

   Two different glycol operating ranges are utilized, depending on the season. This is described in the station chemistry procedure, and the purpose is to balance the competing interests of effective heat transfer in the summer and adequate freeze protection in the winter. Feed and bleeds are performed in the spring and fall to adjust the chemistry to the appropriate band for the upcoming season.

   This was the first time that the phosphate-based corrosion inhibitor regimen was used in the winter, since the transition from a nitrile-based inhibitor to the phosphate-based inhibitor had occurred in April 2017. The station procedural concentration limit for phosphate was established by chemistry personnel at a level conservative to the limit provided by the vendor.

   The elevated phosphate concentration issue was discussed with the vendor, as well as independently discussed with two other chemistry vendors. All concurred that there would be no adverse effects on system materials because of the elevated phosphate concentration. In order to conform with the limit recommended by the vendor and to provide a wider operational band, the plant procedure was changed to be consistent with the vendor limit.

8. In April 2019, an effectiveness review was performed on the Chemistry Control Program for Primary Systems AMA (UFSAR Section 18.2.4) and Chemistry Control Program for Secondary Systems AMA (UFSAR Section 18.2.5) that includes Closed Treated Water Systems among its inspection activities. The AMAs were evaluated against the performance criteria identified in NEI 14-12, “Aging Management Program Effectiveness.” No gaps were identified by the effectiveness review.

9. In September 2019, during the Fall refueling outage, engineering completed a walkdown of the Unit 1 neutron shield tank bottom to inspect the component cooling leakage. The Unit 1 neutron shield tank leakage at a power range detector instrument tube was originally identified in 2004 and the leakage at a neutron flux detector was identified in 2001. All other detector well bottom flanges were inspected with no evidence of leakage. Trend data recorded from the most recent inspection performed in September 2019 stated there was no active leakage.

In March 2019, during the Spring refueling outage, engineering completed a walkdown of the Unit 2 neutron shield tank bottom to inspect the component cooling leakage. A leak rate of 3 drops per minute (DPM) from a power range detector instrument tube was observed. Both wet and dry chromates were evident in the permanent catch container and all leakage was contained in the catch container. Since 2015 the leakage has remained between 8 to 12 DPM. The 3 DPM is the lowest leak rate recorded to date. The leakage observed during the 2019 refueling outage is consistent with the leakage observed during the previous refueling outage. Since the trend remains consistent with previous years, no action was required at this time. A follow-on inspection has been created to track the next inspection.

The Unit 1 and Unit 2 neutron shield tanks are monitored and trended in the Corrective Action Program every refueling outage for leakage. The leak rate is not challenging the inventory of the of the neutron shield tanks. The leakage is a housekeeping issue. The water contains chromates which are hazardous when airborne. The leakage is not a safety concern. A permanent catch container is installed at each Unit as a solution to addressing the housekeeping and health hazards.

An Engineering evaluation concluded that with no significant degrading trend observed over the past 25 years of service and the ability to make up the Neutron Shield Tank with the Neutron Shield Surge Tank, along with the low level alarm monitoring, the leakage can continue to be monitored and trended each refueling outage.

The above examples of operating experience provide objective evidence that the *Closed Treated Water Systems* program includes chemistry control of system water and inspections of system internal surfaces to identify loss of material, cracking, and reduction of heat transfer for components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Closed Treated Water Systems* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Closed Treated Water Systems* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Closed Treated Water Systems* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.13 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

Program Description

The *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program is an existing condition monitoring program that manages cracking, loss of material due to corrosion and wear, and loss of preload on bolted connections for cranes and hoists within the scope of subsequent license renewal. The inspection and test activities specified in this program are consistent with the following requirements identified in UFSAR Section 9.6.4.6:

- ANSI B30.2.0-1976, “Overhead and Gantry Cranes (Top Running Bridge, Multiple Girder)”
- ANSI B30.11-1973, “Monorail Systems and Underhung Cranes”
- ANSI B30.16-1973, “Overhead Hoists”
- NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants”

The cranes, hoists, monorails, and rigging beams within the scope of subsequent license renewal include those previously evaluated as part of compliance with NUREG-0612, as well as other equipment handling systems operating over safety-related equipment. Also within the scope of subsequent license renewal are fuel and equipment handling systems that handle loads over fuel and safety-related equipment.

The *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program uses periodic visual inspections (general visual, VT-1 and VT-3) and non-destructive examination (NDE) surface examinations to manage cracking and loss of material. Structural bolting is also monitored for loss of preload by inspecting for loose or missing bolts, or nuts. Inspection frequencies are consistent with the recommendations within the ASME/ANSI B30 series of standards. For handling systems that are infrequently in service, such as those only used during refueling outages, periodic inspections are performed prior to use. Cranes and hoist inspections do not include inspection of the structures that support the cranes. The individual structures and structural components are examined by the *Structures Monitoring* program (B2.1.34).

The *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program is an existing program that is consistent with NUREG-2191, Section XI.M23, Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. The initial license renewal polar crane girder inspection was completed for Unit 2 in the spring 2010 refueling outage. The internal box girder bolting, weld and material loss inspection was completed by a direct visual inspection performed through available six and 3.5-inch girder vent openings. Light patches of rust were identified on the cab girders but no rust was identified on the trolley girders. No loose bolting, broken welds or loss of material was identified. The trolley girders are open, and the inspection did not identify any rust or material loss.
2. The manipulator crane rail was identified as out of alignment while in use during the fall 2011, Unit 2, refueling outage. An initial evaluation determined no corrective action was required. An additional follow-on visual inspection of the rail was performed with no issues being identified. During the spring 2013 refueling outage the compliance inspection did not identify any issues during the rail inspection.
3. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion was reached that no performance deficiencies or learning opportunities were identified for the Inspection Activities - Load Handling Cranes and Devices AMA (UFSAR Section 18.2.10).
4. The required initial license renewal polar crane girder inspection for Unit 1 was completed in the fall 2016 refueling outage. The internal box girder inspection for bolting, welds and material loss was completed by a direct visual inspection performed through available six and 3.5-inch girder vent openings and identified only minor surface rust. No bolting or weld issues were identified, and the overall inspection was determined to be satisfactory.

5. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.
6. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the Inspection Activities - Load Handling Cranes and Devices AMA (UFSAR Section 18.2.10).
7. In April 2019, an effectiveness review was performed on the Inspection Activities - Load Handling Cranes and Devices AMA (UFSAR Section 18.2.10). The AMA was evaluated against the performance criteria identified in NEI 14-12, "Aging Management Program Effectiveness". No gaps were identified by the effectiveness review.

The above examples of operating experience provide objective evidence that the *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program includes activities to perform visual inspections and surface NDE examinations to identify loss of material is not occurring due to general corrosion or wear and the bridges, structural members, and structural components do not exhibit deformation or cracking. In addition, bolted connections are monitored for loss of material, cracking, and loose bolts, missing or loose nuts, and other conditions indicative of loss of preload, and to initiate corrective actions. Occurrences identified under the *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.14 Compressed Air Monitoring

Program Description

The *Compressed Air Monitoring* program is an existing preventive and condition monitoring program that manages loss of material. The *Compressed Air Monitoring* program includes monitoring of air moisture content and contaminants such that specified limits are maintained, and performance of opportunistic inspections of components for indications of loss of material.

This program is consistent with the response to NRC Generic Letter 88-14 (GL 88-14), “Instrument Air Supply Problems,” and INPO SOER 88-01, “Instrument Air System Failures”. The program relies on guidance and standards provided in EPRI TR 108147, “Compressor and Instrument Air System Maintenance Guide: Revision to NP-7079,” and ANSI/ISA-S7.3-1975, “Quality Standard for Instrument Air,” for testing and monitoring air quality and moisture. The *Compressed Air Monitoring* program activities implement the moisture content and contaminant criteria of ANSI/ISA-S7.3-1975 (incorporated into ISA-S7.0.01-1996).

Program activities include air quality checks at various locations to ensure that dew point, particulates, and hydrocarbons are maintained within the specified limits. Opportunistic inspections of select compressed air system components internal surfaces for loss of material due to corrosion are performed. The effects of corrosion and presence of contaminants are detected during semi-annual surveillance monitoring activities. The procedures and maintenance activities for these activities will include specific inspection acceptance criteria. The opportunistic inspections of accessible internal surfaces of compressed air system components provide assurance that the associated systems within the scope of subsequent license renewal will perform their intended function.

The monitoring methods are effective in detecting the applicable aging effects and prevent significant age-related degradation. Deficiencies are documented in the Corrective Action Program and evaluations are performed for results that do not satisfy established criteria.

NUREG-2191 Consistency

The *Compressed Air Monitoring* program is an existing program that is consistent with NUREG-2191, Section XI.M24, Compressed Air Monitoring.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Compressed Air Monitoring* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 1987, following a water intrusion event, unacceptable amounts of water and excessive levels of oil contaminated the instrument air system. To provide increased reliability, comply with the commitments made in response to GL 88-14, and eliminate the use of contaminated construction air as a backup to either service air or instrument air, service and instrument air modifications were implemented in two phases. Phase 1: A design change replaced the existing instrument air dryers (refrigerant-type) with heatless regenerative type air dryers, removed one instrument air compressor and two service air compressors, and replaced one of the two existing “temporary” instrument air compressors with an oil-free, rotary screw compressor aligned as the normal source of plant instrument air. Phase 2: A design change installed two oil-free, rotary screw, water-cooled instrument air compressors, and replaced the temporary instrument air compressors and their piping with two oil-free, rotary screw, air-cooled service air compressors. A review of the Corrective Action Program has not identified a recurrence of similar type events since installation of the modifications.
2. In January 2003, the two-stage reciprocating service water instrument air compressors became increasingly unreliable, requiring frequent and costly maintenance. As a result, the installed desiccant compressed air dryers were replaced with dual stage regenerative desiccant compressed air dryers. There have been no adverse conditions or age related degradation identified during maintenance and periodic inspections performed since replacement of the air compressors.
3. In June 2014, a review of instrument air quality sampling data over five years from 2003 through 2008 was performed. No adverse trends were identified, based on the instrument air quality acceptance criteria. An Engineering review of condition reports was also performed and no issues related to instrument air quality were identified. However, based on a review of the instrument air quality sampling methods/techniques, the following changes and enhancements were performed:
   - The procedure for the annual performance of instrument air hydrocarbon performance testing was deleted and incorporated into one procedure that encompassed all required instrument air quality sampling, including the requirement for testing on a semi-annual (six month) frequency. (Note that the review of the sampling methods and air quality performance trends provided the basis to maintain the current semi-annual frequency).
   - Procedures were also revised and combined to align the required air quality sampling in accordance with industry guidance.

4. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion was reached that no performance deficiencies or learning opportunities were identified for the Work Control Process AMA (UFSAR Section 18.2.19) related to Compressed Air Monitoring activities.
5. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.
6. In June 2016, a review of instrument air quality sampling data over five years from 2011 through 2016, was performed and found no adverse trends based on the instrument air quality acceptance criteria. In November 2015, the measured dewpoint at the outlet of the Auxiliary Building instrument air dryer was outside the instrument air performance testing procedure acceptance criteria, but the margin measured between the instrument air dewpoint and the ambient temperature at the site was within that determined acceptable by the industry standard. The desiccant was changed out in the dryer in April 2016, the dewpoint measured at the discharge sample point was within the acceptable limit, and the dryer was determined operable.
7. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the Work Control Process AMA (UFSAR Section 18.2.19) related to Compressed Air Monitoring activities.
8. In April 2019, an effectiveness review was performed on the Work Control Process AMA (UFSAR Section 18.2.19) that includes Compressed Air Monitoring among its inspection activities. The AMA was evaluated against the performance criteria identified in NEI 14-12, “Aging Management Program Effectiveness.” No gaps were identified by the effectiveness review related to Compressed Air Monitoring activities.

The above examples of operating experience provides objective evidence that the *Compressed Air Monitoring* program includes activities to perform air quality checks at various locations to identify loss of material on the internal surfaces of compressed air system components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Compressed Air Monitoring* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Compressed Air Monitoring* program will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Compressed Air Monitoring* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.15 Fire Protection

Program Description

The *Fire Protection* program is an existing condition and performance monitoring program that requires periodic visual inspections of fire barrier components and functional testing of fire doors and halon and low pressure carbon dioxide fire suppression systems. The program manages:

- Loss of material for fire-rated doors, fire damper assemblies, the halon systems, RCP oil collection system, steel seismic gap covers and the low-pressure carbon dioxide systems
- Loss of material or cracking for concrete structures, including fire barrier walls, ceilings, and floors
- Hardening, shrinkage, and loss of strength for elastomer fire barrier penetration seals and seismic gap elastomers
- Loss of material and cracking for non-elastomer fire barrier penetration seals, fire stops, containment radiant energy shields, fire wraps, and coatings

The *Fire Protection* program requires visual inspections of not less than 20% of the penetration seals every twelve months, such that 100% of the seals are inspected every five years. The program specifies visual inspections of the fire barrier walls, ceilings and floors in structures within the scope of subsequent license renewal every five years. The visual inspections of fire barriers include determining the condition of fire wraps every eighteen months. The eighteen-month frequency also is applicable for visual inspections of fire doors and damper assemblies. Periodic functional checks are performed on the fire doors.

The program also provides for aging management of external surfaces of the halon systems and low-pressure carbon dioxide fire systems components that are within the scope of license renewal through periodic visual inspections for corrosion that may lead to loss of material. The program includes functional testing of the halon systems and low-pressure carbon dioxide fire suppression systems components in accordance with the Technical Requirements Manual.

Personnel performing inspections are qualified and trained to perform the inspection activities. Unacceptable conditions are entered into the Corrective Action Program for disposition.

NUREG-2191 Consistency

The *Fire Protection* program is an existing program that, following enhancement, will be consistent, with NUREG-2191, Section XI.M26, Fire Protection.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Monitoring and Trending (Element 5)

1. Procedures for fire barrier penetration seals, fire barriers, fire damper assemblies, and fire doors will be revised to require, where practical, identified degradation to be projected until the next scheduled inspection. 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 subsequent period of extended operation based on the projected rate and extent of degradation.

Corrective Actions (Element 7)

2. Procedures will be revised to require that if degradation is detected within the inspection sample of penetration seals, the scope of the inspection is expanded to include additional seals in accordance with the Corrective Action Program. Additional inspections would be 20% of each applicable inspection sample; however, additional inspections would not exceed five. If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the Corrective Action Program.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Fire Protection* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In October 2011, a hair-line crack was observed in a Marinite® fire-stop board attached to the bottom of a cable tray. This crack was approximately 10 inches long at one corner of the board. The fire stop board provides separation from equipment of the opposite train. The Engineering Appendix R Coordinator determined that the crack did not alter the ability of the Marinite® board to meet the separation requirements between trays in this location. The damaged Marinite® board was subsequently replaced.
2. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion was reached that no performance deficiencies or learning opportunities were identified for the Fire Protection Program AMA (UFSAR Section 18.2.7).

3. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.
4. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the Fire Protection Program AMA (UFSAR Section 18.2.7).
5. In April 2019, an effectiveness review was performed on the Fire Protection Program AMA (UFSAR Section 18.2.7). The AMA was evaluated against the performance criteria identified in NEI 14-12, “Aging Management Program Effectiveness.” No gaps were identified by the effectiveness review.
6. In August 2019, a search for plant-specific OE related to fire barriers and fire suppression systems from November 2008 to January 2019 was performed. Although cases of degraded firewall caulking, torn fire door seals, and damaged counter weights for a CO_2 damper louver were identified, there were no conclusive examples of applicable aging effects (i.e., loss of material, cracking, hardening, loss of strength, or shrinkage) due to the aging mechanisms of corrosion, stress corrosion cracking, elastomer degradation, or wear.

The above examples of operating experience provide objective evidence that the *Fire Protection* program includes activities to perform visual inspections to identify cracking, loss of material, hardening, shrinkage and loss of strength for structures and components including fire-rated doors, fire damper assemblies, halon systems, RCP oil collection system, seismic gap covers, low-pressure carbon dioxide systems, fire barriers, penetration seals, fire stops, fire wraps, and coatings within the scope of subsequent license renewal and to initiate corrective actions. Occurrences identified under the *Fire Protection* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Fire Protection* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Fire Protection* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.16 Fire Water System

Program Description

The *Fire Water System* program is an existing condition monitoring program that manages cracking, flow blockage, and loss of material, for in-scope water-based fire protection systems. This program manages aging by conducting periodic visual inspections, flow testing, and flushes performed in accordance with the 2011 Edition of National Fire Protection Association (NFPA) 25, “Standard for The Inspection, Testing and Maintenance of Water-Based Fire Protection Systems,”.Testing and inspections are conducted on a refueling outage interval as allowed by NUREG-2191, Section XI.M27, Table XI.M27-1, “Fire Water System Inspection and Testing Recommendations.” There are no nozzle strainers, glass bulb sprinklers, fire water storage tanks, or foam water sprinkler systems within the scope of subsequent license renewal.

The *Fire Water System* program will include testing a representative sample of the sprinklers prior to fifty years in service with additional representative samples tested at 10-year intervals. Sprinkler testing will be performed consistent with the 2011 Edition of NFPA 25, Section 5.3.1. Fire protection sprinkler system in-service dates vary, and require sprinkler testing or replacement to be completed beginning by 2023 (50 years of service).

Portions of water-based fire protection system components that have been wetted, but are normally dry, such as dry-pipe or pre-action sprinkler system piping and valves, were designed and installed with a configuration and pitch to allow draining. With the exception of two locations, Engineering walkdowns confirmed the as-built configuration that allows draining and does not allow water to collect. Corrective actions have been initiated for the two locations to verify a flow blockage condition does not exist and to restore the locations to the original configuration requirements that allow draining and do not allow water to collect. After corrective actions for the locations are completed, portions of the water-based fire protection system that were wetted, but are normally dry, will not be subjected to augmented testing and inspections beyond those required by NUREG-2191, AMP XI.M27, Table XI.M27-1.

The water-based fire protection system is normally maintained at required operating pressure and is monitored such that loss of system pressure is detected and corrective actions initiated. A low-pressure condition is alarmed in the main control room by the auto start of the electric motor-driven fire pump, followed by the start of the diesel-driven fire pump if the low-pressure condition continues to degrade. The status of the fire pumps is indicated in the main control room and at the fire pump control panels in the Intake Structure Fire Pump House (electric motor-driven fire pump) and the Service Water Pump House (diesel-driven fire pump). Both fire pumps may be manually started from the main control room.

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 to obstruct piping or sprinklers is detected, the material is removed, and the source is detected and corrected.

Inspections and tests are performed by personnel qualified in accordance with procedures and programs to perform the specified task. Non-code inspections and tests follow procedures that include inspection parameters for items such as lighting, distance, offset, presence of protective coatings, and cleaning processes that ensure an adequate examination.

If a flow test (i.e., NFPA 25, 2011 Edition, Section 6.3.1) or a main drain test (i.e., NFPA 25, 2011 Edition, Section 13.2.5) does not meet the acceptance criteria due to current or projected degradation, additional tests are or will be conducted. The number of increased tests is determined in accordance with the Corrective Action Program; however, there are no fewer than two additional tests for each test that did not meet the acceptance criteria. The additional inspections are completed within the interval (i.e., five years or annual/refueling) in which the original test was conducted. If subsequent tests do not meet the acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of tests required. The additional tests will include at least one test at the other unit on site with the same material, environment, and aging effect combination.

In addition to piping replacement, actions will be taken to address instances of recurring corrosion due to microbiologically influenced corrosion (MIC) or pitting on the internal surfaces of fire protection system steel piping. Low Frequency Electromagnetic Technique (LFET) or similar scanning technique will be used for screening 100 feet of accessible piping during each refueling cycle to detect changes in the wall thickness of the pipe. Thinned areas found during the LFET scan are followed up with pipe wall thickness examinations to ensure aging effects are managed and that wall thickness is within acceptable limits. In addition to the pipe wall thickness examination, opportunistic visual inspections of the fire protection system will be performed whenever the fire water system is opened for maintenance. The piping age, time in service, and susceptibility to corrosion will be considered in determining sample locations.

Aging of the external surfaces of buried and underground fire main piping is managed by the *Buried and Underground Piping and Tanks* program (B2.1.27). Loss of material and cracking of the internal surfaces of cementitious lined buried and underground fire main piping are managed by the *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28).

NUREG-2191 Consistency

The *Fire Water System* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI M27, Fire Water System.

Exception Summary

The following program element is affected:

Detection of Aging Effects (Element 4)

1. NUREG-2191, Table XI.M27-1, Note 10 directs inspections/testing of the fire pump suction screen, which recommends the pump suction screens be inspected for signs of degradation on a refueling outage interval based on operating experience. The circulating water and service water traveling screens will be monitored for a change in differential pressure since the water flow to the fire protection pumps travels through the respective circulating or service water traveling screens prior to the fire pump suction strainers.

Justification for Exception:

NUREG-2191, Section XI.M27, Table XI.M27-1 for fire pump suction screen inspection, uses guidance in NFPA-25, 2011 Edition, Section 8.3.3.7 that requires inspection and clearing of any debris or obstructions after the water flow portions of the annual test or fire protection system activations. The circulating water and service water traveling screens will be monitored for a change in differential pressure (dp) since the water flow to the fire protection pumps travels through the respective circulating water or service water traveling screens prior to the fire pump suction strainers. The dp across the circulating water and service water traveling screens are monitored once per shift by Operations personnel and the dp is recorded in the logs and trended for a change (10.0 inches and 3.5 inches maximum, respectively) as an indication of potential flow blockage. The circulating water and service water screen wash operation are automatically initiated on increasing differential pressure. A main control room alarm indicates high differential pressure and requires operator corrective actions.

Both the diesel and motor driven fire pumps are equipped with suction strainers that meet the requirements of NFPA 20, Section 7.3.4.3, with a screen opening size of 0.5 inches. The wet pit suction screening (circulating water and service water traveling screens) requirement of NFPA 20, Section 4.16.8.6, requires a maximum opening size of 0.5 inches. The circulating water and service water traveling screens have a 3/8-inch opening size, which is expected to ensure debris will not enter the fire pump suction strainer. A historical review of work orders since 1993 revealed no indication of any flow blockage of either fire pumps' suction.

Monitoring and trending of the circulating water and service water traveling screens dp will ensure clearing of any debris or obstructions from the fire protection suction is performed as a result of pump activations.

2. NUREG-2191, Table XI.M27-1, Note 10, recommends main drain tests at each water-based system riser to determine if there is a change in the condition of the water piping and control valves on an annual or refueling outage interval. Main drain tests will be performed on 20% of the standpipes and risers every refueling cycle.

Justification for Exception

As indicated by NUREG-2191, Section XI.M27, Table XI.M27-1, Note 10, access for some inspections is feasible only during refueling outages which are scheduled every 18 months. Main drain tests on 20% of the standpipes and risers every 18 months (refueling outage interval) provides adequate information to determine the fire water piping is being maintained consistent with the design basis.

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Parameters Monitored or Inspected (Element 3); Detection of Aging Effects (Element 4); Monitoring and Trending (Element 5); Acceptance Criteria (Element 6); and Corrective Actions (Element 7)

1. Procedures will be developed or revised to specify:
    a. Standpipe and system flow tests for hose stations at the hydraulically most limiting locations for each zone of the system on a five-year interval to demonstrate the capability to provide the design pressure at required flow
    b. Wet pipe main drain testing will be performed on 20% of the standpipes and risers every 18 months on a refueling cycle basis. Acceptance criteria will be based upon monitoring flowing pressures from test to test to determine if there is a 10% reduction in full flow pressure when compared to previously performed tests. The Corrective Action Program will determine the cause and necessary corrective action.
    c. If a flow test or a main drain test does not meet acceptance criteria due to current or projected degradation additional tests are conducted. The number of increased tests is determined in accordance with the corrective action process; 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 in which the original test was conducted. If subsequent tests do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of tests. The additional tests include at least one test at the other unit with the same material, environment, and aging effect combination.
    d. Main drains for the standpipes associated with hose stations within the scope of subsequent license renewal will also be added to main drain testing procedures.
2. Procedures will be revised to perform internal visual inspections of sprinkler and deluge system piping to identify internal corrosion, foreign material, and obstructions to flow. Follow-up volumetric examinations will be performed if internal visual inspections detect an unexpected level of degradation due to corrosion product deposition. If organic or foreign material, or internal flow blockage that could result in failure of system function is identified,

then an obstruction investigation will be performed within the Corrective Action Program that includes removal of the material, an extent of condition determination, review for increased inspections, extent of follow-up examinations, and a flush in accordance with NFPA 25, 2011 Edition, Annex D.5, Flushing Procedures. The internal visual inspections will consist of the following:

a. Wet pipe sprinkler systems - 50% of the wet pipe sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote sprinkler, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. During the next five-year inspection period, the alternate systems previously not inspected shall be inspected.

b. Pre-action sprinkler systems - pre-action sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.

c. Deluge systems - deluge systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.

3. Procedures will be revised to perform system flow testing at five-year intervals with flows representative of those expected during a fire. A flow resistance factor (C-factor) will be calculated to compare and trend the friction loss characteristics to the results from previous flow tests.

Detection of Aging Effects (Element 4), and Monitoring and Trending (Element 5), and Acceptance Criteria (Element 6)

4. Procedures will be revised to address recurring internal corrosion with the use of Low Frequency Electromagnetic Technique (LFET) or a similar technique on 100 feet of piping during each refueling cycle to detect changes in the pipe wall thickness. The procedure will specify thinned areas found during the LFET screening be followed up with pipe wall thickness examinations to ensure aging effects are managed and wall thickness is within acceptable limits. In addition to the pipe wall thickness examination, the performance of opportunistic visual inspections of the fire protection system will be required whenever the fire water system is opened for maintenance. The piping age, time in service, and susceptibility to corrosion should be considered in determining sample location priorities.

Detection of Aging Effects (Element 4)

5. The Unit 2 lube oil purification and hydrogen seal oil piping will have the piping pitch adjusted to improve drainage. A drain valve will be installed on the Unit 2 hydrogen seal oil fire protection piping to drain the line after system testing or initiation. As part of the drainage

reconfiguration, visual inspections and wall thickness measurements will be performed to identify unexpected degradation. Piping with unexpected degradation will be replaced.

6. The activity of the jockey pump (i.e., an increase in the number of pump starts or run time of the pump) will be monitored consistent with the “detection of aging effects” program element of NUREG-2191, Section XI.M41.
7. At each unit, a sample of 3% or a maximum of ten wet pipe sprinklers with no more than four sprinklers per structure shall be tested. Testing is based on a minimum time in service of fifty years and severity of operating conditions for each population.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Fire Water System* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In September 2012, an inspection of the fire water system piping identified debris on the internal surfaces. The external condition of the pipe was observed to be thinning with excessive rust. The piping section was subsequently replaced.
2. In May 2013, sections of cementitious lined cast iron piping were replaced with a higher pressure rated cementitious lined ductile iron piping. Additional isolation valves were also installed to improve system sectional isolation capability. These modifications were implemented due to six fire protection pipe failures that occurred from 1984 to 2003 because of either manufacturing flaws or a flaw that was initiated during the installation process. There were no reported instances due to age related degradation. The metallurgical failure reports for these pipe failures did not attribute any of the failures to the cementitious liner. Several of the materials analysis reports stated the cementitious liner was tightly adhered to the pipe or in good contact with the existing pipe. All the internal pipe failures were attributed to preexisting conditions and not due to the failure of the lining.
3. In November 2014, a small through wall leak was identified in the bottom of a 90-degree elbow on the Unit 2 turbine lube oil purification fire protection deluge system. Engineering evaluated the system as capable of supplying the required water flow and pressure to meet the design requirement. The cause of the through wall leak was attributed to residual water left in the system following testing. Actions were taken to ensure the affected piping was drained following deluge testing. There has not been any further identified through wall leaks since this action was implemented. Permanent repair of this section of pipe is being developed.
4. In March 2014, a level decrease in the fire protection hydro-pneumatic tank resulted in the system maintenance pump cycling on and off at an increased rate. The pump discharge check valve was replaced due to suspected leak-by, pitting on the seating surface and disc. During

the check valve replacement, a portion of the pipe was replaced due to partial blockage and a temporary pipe repair was performed to stop the leak. In December 2014, evidence of a buried fire protection pipe leak was observed during a fire protection system walkdown at the intake structure. The leak appeared to be associated with small diameter carbon steel piping between the system pressure maintenance pump and the hydro-pneumatic tank where the fire protection piping enters the rip-rap lined embankment adjacent to the intake structure. The affected carbon steel piping was replaced and restored to service. A follow-on Engineering walkdown observed the tank level and pressure remained steady.

5. In January 2015, a work order was initiated to perform an internal inspection of the motor-driven fire pump discharge piping (on the system side of the discharge check valve). The inspection addressed the extent of condition for the Unit 2 Turbine Building 12-inch fire protection above ground supply piping developed a leak and was replaced coming out of the 2014 Unit 2 refueling outage. Visual inspection of the piping identified it was in very good condition with only minimal signs of corrosion.

6. In October 2015, an inspection for the SBO fire protection pre-action sprinkler system was unsatisfactory due to some minor sediment in the piping. The inspection was performed on a small section of piping that had not been completely drained following past testing. To facilitate the inspection, the drain valve and associated spool piece were removed. The inspection found minor sediment but no indication of loss of material or formation of tubercles in the piping. The sediment collected due to the stagnant water conditions at the rim of fitting transitions. The remaining portions of the system were maintained dry. The sediment observed was not significant and would not block flow to the battery room sprinkler. The test procedure was revised to ensure this section of piping is adequately drained.

7. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion was reached that no performance deficiencies or learning opportunities were identified for the Fire Protection Program AMA (UFSAR Section 18.2.7).

8. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

9. In June 2016, a through wall pipe leak was discovered on a Unit 2 fire protection supply line elbow located in the overhead of the Turbine Building. The elbow was located at the bottom of a short vertical run of piping which filled with stagnate water. The system was only drained and refilled when maintenance was required (such as replacing damage sprinklers, system valves, or removal of piping to facilitate outage activities). A metallurgical analysis was performed on the removed section of piping. The metallurgical analysis confirmed the leak originated internally to the elbow. The internal surface of the piping that was removed was visually consistent with other sections of the Turbine Building sprinkler systems previously inspected (black magnetite layer with some very small nodules). The examined pipe segment was found to have some small nodules but minimal wall loss. The material loss at the leak location was not consistent with the overall condition of the remainder of the pipe segment. Based on the visual condition of the removed piping, metallurgical analysis, prior internal inspections of stagnant wet fire protection lines, and planned supplemental inspections, Engineering determined no additional inspections or actions were required. The leaking elbow and pipe segment were replaced.

10. In May 2017, two fire protection valves were disassembled due to excessive leak-by. Build-up of debris with corrosion products was found inside the valve bodies. The deposit was a combination of corrosion products and sediment that had been compacted down over the years and required extensive scrubbing to remove. Engineering determined the valves were original plant equipment that were continuously exposed to water and the amount of material deposited on the valve body was not excessive and unlikely to be removed by flushing. Engineering performed an evaluation to determine what actions could be made to prevent debris build-up. Increasing the flushing frequency was determined to not provide any additional debris removal. Engineering determined the existing flushing methodology and frequency was the best available option for debris removal and mechanical cleaning would be performed, if required.

11. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the Fire Protection Program AMA (UFSAR Section 18.2.7)

12. In April 2019, an effectiveness review was performed on the Fire Protection Program AMA (UFSAR Section 18.2.7) that includes inspection for corrosion loss of material, cracking, and flow blockage among its inspection activities. The AMA was evaluated against the performance criteria identified in NEI 14-12, “Aging Management Program Effectiveness.” Gaps were identified by the effectiveness review related to addressing corrosion in the fire water system. Procedures were identified to lack specific criteria related to aging inspections. Several system test and operating procedures were determined to not use existing valves to

drain the section of pipe after a test or actuation. Open work orders to replace piping, obtain piping ultrasonic testing (UT) examination data, perform internal inspections and adjust piping pitch for drainage were identified as not being completed. Both the Unit 1 and Unit 2 Turbine Building fire protection 10-inch and 12-inch deluge supply piping have been replaced or are scheduled to be replaced. Procedure updates have been completed to use existing valves to drain the system piping. Work orders to perform UT examinations on the Unit 2 hydrogen seal oil deluge system and other internal pipe inspections and work orders for pipe replacement are being scheduled.

Recurring Internal Corrosion (RIC)

Recurring internal corrosion, including through-wall failures as a result of loss of material due to pitting or MIC has occurred on several occasions. Periodic fire protection system piping flushes, flow testing and piping thickness measurements will be performed to identify pipe degradation prior to loss of system intended function. The Unit 1, 12-inch Turbine Building Fire Protection piping header has been replaced. Replacement of the Unit 2, 10 and 12-inch piping headers are scheduled. Internal 10-inch pipe inspections are scheduled for Unit 1 and 2. Follow-up ultrasonic testing of pipes with trapped water sections has been completed with no indication of increased corrosion rates or pipe wall thinning. In addition to recent piping replacements and inspections in the Turbine Building and the Auxiliary Building to address instances of RIC due to pitting or MIC, Low Frequency Electromagnetic Technique (LFET) or a similar technique on 100 feet of piping will be performed during each refueling cycle to detect changes in the pipe wall thickness. Thinned areas found during the LFET scan are followed-up with pipe wall thickness examinations to ensure aging effects are managed and that wall thickness is within acceptable limits. In addition to the pipe wall thickness examination, opportunistic visual inspections of the fire protection system will be performed whenever the fire water system is opened for maintenance.

The above examples of operating experience provides objective evidence that the *Fire Water System* program includes activities to perform periodic fire main and hydrant inspections and flushing, sprinkler inspections, functional test, and flow tests to identify cracking, flow blockage, and loss of material for in-scope water-based fire protection systems within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Fire Water System* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Fire Water System* program, following enhancement, will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

The continued implementation of the *Fire Water System* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.17 Outdoor and Large Atmospheric Metallic Storage Tanks

Program Description

The *Outdoor and Large Atmospheric Metallic Storage Tanks* program is an existing condition monitoring program that manages the effects of loss of material and cracking on the outside and inside surfaces of aboveground metallic tanks constructed on concrete or soil. This program manages aging effects associated with outdoor tanks with internal pressures approximating atmospheric pressure including the refueling water storage tanks (RWSTs), refueling water chemical addition tanks (CATs), casing cooling tanks (CCTs), and emergency condensate storage tanks (ECSTs).

The program includes preventive measures to mitigate corrosion by protecting the external surfaces of steel components consistent with standard industry practices. The RWSTs and CCTs are insulated and rest on a concrete mat/foundation covered with an oil sand cushion. Caulking is used at the concrete-component interface of the RWSTs. Caulking is used at the concrete-component interface of the CCTs, where there are no grout pads.

The CATs are insulated, and skirt supported. The insulation jacketing on the RWSTs, CATs, and CCTs is corrugated aluminum (with a factory applied moisture barrier) with overlapped seams. The ECSTs are internally coated and protected by concrete missile barriers.

The program manages loss of material on tank internal bare metal surfaces by conducting visual inspections. Surface exams of external tank surfaces are conducted to detect cracking on the stainless steel tanks. Inspections of RWST and CCT caulking/sealants are supplemented by physical manipulation. UT examinations of the tanks' bottoms are conducted to ensure that design thickness and corrosion allowance criteria are met. A periodic sampling-based inspection is used on the external surfaces of insulated tanks. Inspections not conducted in accordance with ASME Code, Section XI requirements are conducted in accordance with plant-specific procedures that include inspection parameters such as lighting, distance, offset, and surface conditions. Additional inspections are conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending); however:

- For inspections where only one tank of a material, environment, and aging effect was inspected, all tanks in that grouping are inspected.
- For other sampling-based inspections there will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at the other unit.

The additional inspections will be completed within the interval (i.e., 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the first half of the next inspection interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval.

If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the Corrective Action Program. However, for one-time inspections that do not meet acceptance criteria, inspections are subsequently conducted at least at 10-year inspection intervals.

The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) manages the internally coated surfaces of the ECSTs. Internal surfaces of the RWSTs, CATs, and CCTs are managed by the *One-Time Inspection* program (B2.1.20). Tank reinforced concrete foundations and the reinforced concrete missile barrier of the ECSTs are managed by the *Structures Monitoring* program (B2.1.34).

NUREG-2191 Consistency

The *Outdoor and Large Atmospheric Metallic Storage Tanks* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks.

Exception Summary

The following program element(s) are affected:

Preventive Actions (Element 2); Parameters Monitored/Inspected (Element 3); Detection of Aging Effects (Element 4); Acceptance Criteria (Element 6); and Corrective Actions (Element 7)

1. NUREG-2191 specifies for outdoor tanks, that sealant or caulking is applied at the interface between the tank external surface and concrete or earthen surface to mitigate corrosion of the tank by minimizing the amount of water and moisture penetrating the interface. The ECSTs do not use caulking or sealant at the concrete-component interface and therefore, do not require inspection of the caulking or sealant. The RWSTs and CCTs have mastic sealant installed on the tank shell between the insulation and the tank concrete foundation to ensure water-tightness and to prevent water from getting to the tank.

Justification for Exception:

The ECSTs are insulated from the outside atmosphere by two inches of expansion joint filler foam and surrounded by a two-foot-thick layer of reinforced concrete that provides missile protection. The concrete missile shield and expansion joint filler foam configuration mitigates corrosion of the tank by minimizing water and moisture from penetrating inaccessible exterior tank surfaces.

The roofs and sides of the RWSTs, CATs, and CCTs are insulated and jacketed to mitigate corrosion of the tank by minimizing the amount of water and moisture on the exterior surfaces. As an additional preventive measure, the RWSTs and CCTs have mastic sealant installed on the tank shell between the insulation and the tank concrete foundation to ensure water-tightness and to prevent water from getting to the tank. The RWSTs, CATs, and CCTs have insulation jacketing installed with overlapping seams to provide a protective outer layer and to prevent water intrusion. The mastic sealant installed on the tank shell between the insulation and the tank concrete foundation provides a boundary to mitigate corrosion of the tank bottom surface and the concrete foundation. In addition, the RWSTs and CCTs bottom surface is protected by an oil sand cushion and caulk at the interface between the tank external surface and the concrete surface. Periodic inspections normally performed on the caulk at the tank and concrete foundation will be performed on the mastic sealant installed on the tank shell between the insulation and the tank concrete foundation. An inspection of the caulk at the tank and concrete foundation interface will be included in the sample when the RWSTs and CCTs external insulation is removed and sampled for external surface visual examinations.

Detection of Aging Effects (Element 4)

2. NUREG-2191 recommends both visual and volumetric inspection techniques to identify degradation on carbon steel tank external surfaces, located outdoors on soil or concrete. The external surface of the ECSTs are encased in a two-foot-thick reinforced concrete missile shield with expansion joint filler foam between the external tank wall and the concrete missile shield. The concrete missile shield prevents visual and volumetric examinations of the external surface of the tank.

Justification for Exception:

The concrete missile shield and the expansion joint filler foam act as multiple barriers protecting the external tank surfaces. One-time thickness measurements of a sample of the Unit 1 and Unit 2 ECSTs interior wall will be performed prior to the subsequent period of extended operation. The samples will examine the ECSTs interior vertical steel shell region from the bottom of the tank along the pipe penetration area, extending six feet vertically up from the tank, as this is a region potentially most susceptible to degradation. The inspection results will be projected to the end of the subsequent period of extended operation to confirm the ECSTs intended functions will be maintained throughout the subsequent period of extended operation based on the projected rate of degradation. Any degradation not meeting acceptance criteria will require periodic 10-year thickness measurements and a sample expansion along the leakage path consistent with the observed degradation.

The program inspects the external bottom surfaces of the ECSTs that are exposed to a soil or concrete environment by performing volumetric examination thickness measurements.

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Preventive Actions (Element 2); Parameters Monitored/Inspected (Element 3); Detection of Aging Effects (Element 4); Acceptance Criteria (Element 6); and Corrective Actions (Element 7)

1. Procedures will be revised to require periodic visual inspections of the RWSTs and CCTs be performed at each refueling outage to confirm that the mastic sealant at the RWSTs and CCTs insulation and concrete foundation interface is intact. The visual inspections of the sealant will be supplemented with physical manipulation to detect any degradation. If there are any identified flaws, the mastic sealant will be repaired or replaced, and follow-up examination of the tank's surfaces will be conducted if deemed appropriate. An inspection of the caulk at the tank and concrete foundation interface will be included in the sample when the RWSTs and CCTs external insulation is removed and the caulk will be sampled for external surface visual examinations ten years before the subsequent period of extended operation. Results will be forwarded to Engineering for evaluation and the need for additional inspections will be determined based on projected corrosion rates.

Detection of Aging Effects (Element 4)

2. Procedures will be revised to require visual and surface examination of the exterior surfaces of the RWSTs, CATs, and CCTs be performed to identify any loss of material or cracking. A minimum of either 25 one-square foot sections or 20% of the surface area of insulation will be required to be removed to permit inspection of the exterior surface of each tank. The procedure will specify that sample inspection points be distributed in such a way that inspections occur near the bottoms, at points where structural supports, pipe, or instrument nozzles penetrate the insulation, and where water could collect such as on top of stiffening rings. If no unacceptable loss of material or cracking is observed, subsequent external surface examinations of insulated tanks will inspect for indications of damage to the jacketing, evidence of water intrusion through the insulation, or evidence of damage to the moisture barrier of tightly adhering insulation.
3. Procedures will be revised to require one-time thickness measurements of a sample of the Unit 1 and Unit 2 ECSTs interior wall prior to the subsequent period of extended operation to assess potential degradation due to leakage identified from the missile shield into the pipe penetration area in the Auxiliary Feedwater Pump House. The samples will examine the ECSTs interior vertical steel shell region from the bottom of the tank along the pipe penetration area, extending six feet vertically up from the tank, as this is a region potentially most susceptible to degradation. The inspection results will be projected to the end of the subsequent period of extended operation to confirm the ECSTs intended functions will be maintained throughout the subsequent period of extended operation based on the projected

rate of degradation. Any degradation not meeting acceptance criteria will require periodic 10-year thickness measurements and a sample expansion along the leakage path consistent with the observed degradation. The upper manway and lower manway gaskets will be replaced during the one-time inspection.

4. Procedures will be revised to require volumetric examination thickness measurements of the bottom of the RWSTs and CCTs be performed each 10-year period during the subsequent period of extended operation starting ten years before the subsequent period of extended operation. Results will be forwarded to Engineering for evaluation and the need for additional inspections will be determined based on projected corrosion rates.

Corrective Action (Element 7)

5. A new procedure will be developed to specify that additional inspections be performed consistent with NUREG-2191.

   If any inspections do not meet the acceptance criteria, additional inspections are conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending).

   a. For inspections where only one tank of a material, environment, and aging effect was inspected, all tanks in that grouping are inspected.

   b. For other sampling based inspections there will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at the other unit.

      The additional inspections will be completed within the interval (i.e., 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the first half of the next inspection interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval.

      If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the Corrective Action Program. However, for one-time inspections that do not meet acceptance criteria, inspections are subsequently conducted at least at 10-year inspection intervals.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Outdoor and Large Atmospheric Metallic Storage Tanks* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 2010, an internal inspection of the Unit 2 RWST was performed using Low Frequency Electromagnetic Technique (LFET) to scan the perimeter of the bottom plates of the RWST, including the weir, allowing adequate assessment of degradation due to pitting. In addition, a scan was performed along the welds in the inspection area. Ultrasonic testing (UT) examinations were performed on the tank bottom. Two indications were identified with the LFET. Both indications were visible topside dents, with UT readings being greater than the nominal design thickness. The inspection concluded that there was no indication of age-related degradation on the Unit 2 RWST bottom.
2. In September 2010, UT examinations were performed on bottom of the Unit 1 CAT in the filled condition, in a two-inch wide ring around the drain pipe. The thickness measurements of the tank bottom exceeded the acceptance criteria. There was no indication of material loss.
3. In September 2013, during the Unit 1 Fall 2013 refueling outage an internal inspection of the Unit 1 RWST was performed in the filled condition. UT examinations of the tank bottom resulted in thicknesses above the nominal design thickness. Internal structures (e.g., piping) were in good condition and no visible pitting of the internal stainless-steel surfaces was observed. Floor plate, internal shell plate and nozzle welds were identified to be in good condition. Visual inspection of the tank did not indicate any adverse conditions or areas of concern. Based on the data collected from this inspection, no measurable corrosion was noted and the readings were at or above the design nominal thickness. As such, no meaningful corrosion rate can be established at this time. Based on no corrosion being found, API Standard 653, “Tank Inspection, Repair, Alteration, and Reconstruction,” calculations show a 20-year inspection interval for this tank.
4. In May 2015, a work order was initiated to locate and resolve rain water leakage between the missile shield and outer tank wall at the Unit 1 ECST. Rain water leakage between the concrete missile shield and the outer surface of Unit 1 and Unit 2 ECSTs has been a chronic condition. The rain water collects between the two surfaces and leaks out of the piping penetrations and onto the floor of the Motor-driven Auxiliary Feedwater (MDAFW) Pump House. Fresh caulk was applied to three conduit penetrations, vent base plates, and the perimeter of vents with missile shields, but did not resolve the leakage issue. Another work order was initiated to identify the source of rain water leakage at the tank and repair the leakage. Piping penetration cover plates were removed to allow inspection of the area

between the missile shield and outer tank wall. A small amount of water was found leaking from the penetration area. New sealant/gasket was applied, and the penetration cover plates were reinstalled. There have been no issues of water leakage at the Unit 1 ECST penetration area since the repair was performed.

5. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion reached was that performance deficiencies or learning opportunities were identified for the Tank Inspection Activities AMA (UFSAR Section 18.1.3). Engineering was tasked with an assignment to consider obtaining more wall/roof shell data on the Unit 1 ECST. An internal inspection was performed consisting of a visual inspection of the interior coating, UT examinations were performed on the tank bottom, wall and roof, and LFET on the bottom and wall. The inspection identified 23 minor coating indications. Coating degradation and minor corrosion were also observed on the angle iron forming the roof/wall joint. Degraded areas identified were cleaned and recoated. UT examination was performed on the tank bottom and on a quarter section of the roof at the roof/wall joint. LFET was performed on the tank bottom and the tank walls. Data obtained on the bottom, wall, and roof was satisfactory showing no indications of significant corrosion or degradation.

6. In July 2016, a small puddle of dark colored water was observed on the bottom of the Unit 2 MDAFW Pump House directly under the MDAFW pump suction isolation valves. The leakage appeared to be coming from the caulked seal where the AFW suction pipes penetrate the missile shield, indicating water intrusion between the tank and the missile shield. The leakage was not active; but staining on the wall indicated the leakage was coming from the pipe penetrations under the MDAFW pump suction isolation valves. During the Spring 2016 Unit 2 refueling outage, the upper manway was inspected for water intrusion and found no damage or leaks. The manway was removed and replaced with a new gasket.

   Engineering developed and implemented an investigation plan to identify any water intrusion paths contributing to the leakage that included:

   a. Replacement of the roof over the Unit 2 MDAFW Pump House, and

   b. while the roof was removed, a walkdown was performed to inspect the 2-inch rattle space between the Unit 2 ECST and missile shield as well as any other potential areas corresponding to the leak, and

   c. after the new roof was installed, Security or Operations personnel checked (on normal rounds) to see if there was still a leak.

   Since the plan was implemented, there has been no evidence of leakage into the Unit 2 MDAFW Pump House.

7. In November 2016, external inspection and insulation replacement was performed on the Unit 1 RWST. Up until that time, in order to determine if any aging degradation was occurring on the exterior of insulated stainless steel tanks, insulation in selected areas was removed and the exterior was visually inspected for loss of material or cracking. Also, in March 2009, the insulation at the top of the Unit 1 RWST was observed to be degrading and falling off. A subsequent design change was developed to define the tank inspection activities, remove insulation from the Unit 1 RWST to perform external tank inspections, replace the insulation with like for like materials, and apply a new layer of weatherproofing protection. Grey aluminum corrugated flashing with a factory applied interior polyfilm moisture barrier covers the insulation. The grey aluminum corrugated flashing vertical seam overlaps are four inches and horizontal seam overlaps are three inches and are held in place with stainless steel bands. Longitudinal overlaps are secured with stainless steel sheet metal screws. The inspections concluded that there were no adverse conditions identified.

8. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.

9. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion reached was that an area for improvement or enhancement was identified for the Tank Inspection Activities AMA (UFSAR Section 18.1.3). Results of the assessment indicated that inspections performed for some tanks under the Tank Inspection Activities AMA were not performed in accordance with the UFSAR description. The UFSAR states, “visual inspections of the internal and external surfaces will be performed. Volumetric examinations will be performed on tanks founded on soil or buried.” However, in accordance with the Tank Inspection Activities AMA, volumetric examinations were performed on some tanks in lieu of internal inspections due to accessibility. In May 2017, Engineering was tasked to evaluate the deficiency and initiate any document changes or additional inspections that may be required. Subsequently, UFSAR Section 18.1.3, Tank Inspection Activities AMA, was updated to address the use of UT examinations in lieu of visual examinations for some tanks.

10. In April 2019, an effectiveness review was performed on the Tank Inspection Activities AMA (UFSAR Section 18.1.3) that includes the RWSTS, CATs, CCTs, and ECSTs among its inspection activities. The AMA was evaluated against the performance criteria identified in NEI 14-12, “Aging Management Program Effectiveness.” No gaps were identified by the effectiveness review.

The above examples of operating experience provides objective evidence that the *Outdoor and Large Atmospheric Metallic Storage Tanks* program includes activities to perform visual inspections of tank internal bare metal surfaces, surface examination of external tank surfaces, and UT examinations of tank bottoms to identify cracking or loss of material for aboveground metallic tanks within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Outdoor and Large Atmospheric Metallic Storage Tanks* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Outdoor and Large Atmospheric Metallic Storage Tanks* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Outdoor and Large Atmospheric Metallic Storage Tanks* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.18 Fuel Oil Chemistry

Program Description

The *Fuel Oil Chemistry* program is an existing mitigative and condition monitoring and preventive program that manages cracking or blistering, flow blockage, hardening or loss of strength, loss of material, and reduction of heat transfer from tanks, piping, and components in a fuel oil environment. The program includes activities which provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of subsequent license renewal.

The fuel oil tanks within the scope of subsequent license renewal include:

- Station blackout (SBO) diesel generator fuel oil day tank
- Emergency diesel generator (EDG) fuel oil day tanks
- Diesel-driven fire pump 2 fuel oil storage tank
- Security diesel generator fuel oil day tank
- Security diesel generator fuel oil supply tank

The fuel oil storage tanks within the scope of subsequent license renewal do not have internal coatings or linings. The fuel oil tanks within the scope of subsequent license renewal are maintained by monitoring and controlling fuel oil contaminants in accordance with Technical Specifications, the Technical Requirements Manual, and ASTM standards. Fuel oil sampling and analysis is performed in accordance with approved procedures for new fuel oil and stored fuel oil.

The program samples fuel oil using the guidelines of the following ASTM standards, as well as additional ASTM standards:

- ASTM D 0975-89, “Standard Specification for Diesel Fuel Oils”
- ASTM D 4057-88, “Standard Practice for Manual Sampling of Petroleum and Petroleum Products”
- ASTM D 6217-98, “Standard Test Method for Particulate Contamination in Middle Distillate Fuels by Laboratory Filtration”
- ASTM D 1796-83, “Standard Test Method for Water and Sediment in Fuel Oil by the Centrifuge Method”

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 oil before its introduction into the storage tanks. Where internal cleaning and inspection are not physically possible, bottom thickness measurements of inaccessible tanks will be performed in lieu of cleaning and internal inspection.

Corrective actions require water to be removed from fuel oil storage tanks when detected and the condition entered in the Corrective Action Program. Additionally, corrective actions, such as the addition of a biocide, are to be taken when the presence of biological activity is confirmed.

The *One-Time Inspection* program (B2.1.20) will be used to verify the effectiveness of the *Fuel Oil Chemistry* program.

The *Fuel Oil Chemistry* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *Fuel Oil Chemistry* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI.M30, Fuel Oil Chemistry.

Exception Summary

The following program element(s) are affected:

Parameters Monitored/Inspected (Element 3); and Detection of Aging Effects (Element 4)

1. Section XI.M30 of NUREG-2191 indicates that loss of material in metallic fuel oil tanks exposed to fuel oil is managed with periodic draining, cleaning and inspection of tank internal surfaces as described in element 4. The underground security diesel fuel oil tank is a newly-installed, double-wall, fiberglass tank potentially susceptible to loss of material, cracking, or blistering of internal surfaces due to fuel oil impurities associated with water and microbiological organisms. A one-time draining, cleaning, and inspection of the security diesel fuel oil tank will be performed between 30 to 40 years of service. In addition, Kynar® polyvinylidene fluoride (PVDF) fuel oil piping installed between the fuel oil tank and the transition sump is also potentially susceptible to hardening or loss of strength, loss of material, cracking or blistering due to fuel oil impurities associated with water and microbiological organisms.

Justification for Exception:

Double wall underground PVDF fuel oil piping was installed between the fuel oil tank and the transition sump in 2014. PVDF piping was specifically chosen for use with fuel oils and is UL-971 listed. The Staff previously concluded that underground PVFD fuel oil piping had no aging effects requiring management [NUREG-1929, Section 3.3.2.3.17 (ADAMS Accession No. ML093020275)]. The PVDF piping experiences flow during diesel operation and is not expected to experience water separation or pooling; therefore, a one-time inspection for fuel oil chemistry effectiveness is not required. In addition, the Staff previously concluded that underground fiberglass diesel fuel oil tanks had no aging effects requiring management [NUREG-1907, Volume 2, Section 3.0.3.2.1 and Section 3.3.2.3.72 (ADAMS Accession No. ML081430109)]. The *Fuel Oil Chemistry* program is assigned to ensure the fluid chemistry remains compatible with the fiberglass tank and PVDF piping materials by managing fuel oil impurities associated with water and microbiological organisms. Aging of the fiberglass tank and PVDF piping exposed to diesel fuel oil is not expected without exposure of the tank's internal surfaces to contaminants in the fuel oil, such as water and microbiological organisms.

The security diesel generator fuel oil tank is sampled quarterly for water and sediment. During sampling, if visible water is detected, the sample is analyzed for aerobic and sulfate reducing bacteria. If microbiological contamination is confirmed, the tank is treated with biocide and resampled to verify the successful treatment/elimination of the microbiological contamination. Corrective actions are taken when water or sampled parameters are out of specification.

In January 2015 a new security diesel generator fuel oil supply tank was installed. A one-time draining, cleaning, and inspection of fuel oil security diesel fuel oil tank will be performed between 30 to 40 years of service to verify *Fuel Oil Chemistry* program effectiveness with managing fuel oil impurities associated with water and microbiological organisms. The 30 to 40 year inspection period is consistent with initial license renewal fuel oil chemistry verifications identified in NUREG-1801 that were performed within ten years of entering the period of extended operation.

In addition, the security diesel generator fuel oil supply tank includes a level probe to monitor fuel level and a leak detection system that can be used to identify tank leakage that would indicate a loss of pressure boundary intended function for the tank. The leak detection system includes volumetric leak detection, two sump sensors and a hydrostatic reservoir sensor. The volumetric leak detection monitors for leaks by periodic tank tightness testing. The two sump sensors monitor for any fluid in the transition and tank sumps. The hydrostatic reservoir sensor detects level changes in the brine-filled reservoir for the interstitial space between the double tank walls. The leak detection system is certified to be in accordance with 40 CFR Part 280, Subpart D - Release Detection. The display console is configured to provide alarms on either low tank level or a tank/pipe leak. The tank/pipe leak alarm is an audible and visual alarm, with acknowledge feature, located on the outside of the Security Diesel Building. Operators record the level reading daily in the security diesel generator fuel oil tank. Corrective actions are taken for readings which are out of specification.

Enhancements

Prior to entering the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Scope of Program (Element 1)

1. The *Fuel Oil Chemistry* program scope will be revised to include the security diesel generator fuel oil day tank.

Preventive Actions (Element 2); Parameters Monitored/Inspected (Element 3); Detection of Aging Effects (Element 4); Monitoring and Trending (Element 5); and Acceptance Criteria (Element 6)

2. Procedure(s) will be revised or developed to drain, clean internally to the extent practical, visually inspect internal surfaces (if physically possible), and perform tank bottom thickness measurements of the following tanks:

    - Emergency diesel generator fuel oil day tanks (procedures are currently available to drain and clean on demand)
    - SBO diesel generator fuel oil day tank (new procedure needed)
    - Diesel-driven fire pump 2 fuel oil storage tank (new procedure needed)
    - Security diesel generator fuel oil day tank (new procedure needed)

    The procedure(s) will require that if evidence of degradation is observed during visual inspection, or if visual inspection is not possible, volumetric inspections will be performed. The draining, cleaning and inspection of each tank will be performed at least once during the 10-year period prior to the subsequent period of extended operation and at least once every 10 years during the subsequent period of operation.

    Procedure(s) will be revised or developed to require an Engineering evaluation be performed to evaluate and trend visual and volumetric (if degradation is detected during inspections) tank inspection results. Unacceptable inspection results will be documented in the Corrective Action Program. Thickness measurements will be evaluated against the design thickness and corrosion allowance. The rate of degradation is evaluated and projected until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection frequency will be adjusted, as necessary, based on the projection.

Preventive Actions (Element 2); Parameters Monitored/Inspected (Element 3); Detection of Aging Effects (Element 4); and Acceptance Criteria (Element 6)

3. Procedures will be revised or developed to perform a one-time draining, cleaning and internal visual inspection of the security diesel generator fuel oil supply tank between 30 and 40 years of service.

   Any degradation found during the internal visual inspection will be addressed by the Corrective Action Program. If degradation is observed, volumetric measurements will be performed.

Monitoring and Trending (Element 5) and Acceptance Criteria (Element 6)

4. Procedures will be updated to clarify the need to specifically monitor and trend water and biological activity in addition to particulates.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Fuel Oil Chemistry* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In February 2009, the carbon steel '2J' emergency diesel generator (EDG) fuel oil day tank was sampled and tested with particulates results out of specification high at 13.19 mg/L. Since concerns relating to high and inconsistent particulate levels were previously identified and evaluated in 2007 by an apparent cause evaluation, another apparent cause evaluation was initiated to review why the previous corrective actions did not prevent re-occurrence. Based on the findings and discussions with industry experts, Engineering concluded that the cause for the reoccurring fuel oil particulate issues associated with the '2J' EDG fuel oil day tank was due to the internal walls of the tank being rusted as a result of condensation from the overflow and vent line. Although all four EDG fuel oil day tanks are considered susceptible to condensation, it was identified that due to its more westerly location, the '2J' overflow and vent piping could have increased condensation build up due to more direct exposure to the weather. Corrective actions included revisions to sampling procedures to include guidance for proper purging and sampling techniques to prevent sample contamination and to obtain a more representative sample. From May 2009 through December 2010, the '2J' EDG fuel oil day tank was sampled and tested with particulate results either out of specification high or trending high. In Fall 2011, the original carbon steel '2J' EDG fuel oil day tank was replaced with a stainless steel tank.
2. From February 2013 to November 2015, quarterly sampling of the carbon steel '2H' EDG fuel oil day tank showed a steadily increasing trend nearing the acceptance limit of 10 mg/L. Of the samples tested at higher than normal levels of particulates, several samples were re-tested and found to be closer to normal levels. The '2H' EDG fuel oil day tank was filtered in December 2015 to ensure particulate levels remained below the acceptance limit. Subsequent to filtering the measurements have remained at or below 3.0 mg/L.

3. In April 2013, it was identified that Dominion had committed to comply with the requirements of the NRC Regulatory Guide 1.137 (RG 1.137) for the underground security diesel generator fuel oil supply tank. RG 1,137 indicated that diesel fuel systems should be in compliance with ANSI 195-1976, “Fuel Oil Systems for Standby Diesel Generators,” which included requirements to perform pressure testing, visual integrity testing and cleaning of the tank at 10-year intervals to remove any accumulated water and sediment. Although this tank had been periodically tested for water and sediment, and no water or sediment issues had been discovered, no evidence could be found that this tank had ever been cleaned or tested in accordance with the requirements of ANSI N195-1976. Since this tank was buried under asphalt with little or no means of ingress/egress, there did not appear to be any way to perform the required inspections of this tank. In response to this condition, in order to support an initial license renewal commitment to perform a one-time inspection of this tank prior to the period of extended operation, the original carbon steel tank was replaced in January 2015 with a new double-walled fiberglass tank.
4. In May 2015, Engineering addressed concerns identified in NRC Information Notice 2006-22 (IN 06-22), “New Ultra-low-sulfur Diesel Fuel Oil Could Adversely Impact Diesel Engine Performance” including the concern relating to incompatible materials such as copper in the fuel oil line to the diesel-driven fire pump. In regard to incompatible materials, the NRC information notice stated that copper and zinc are incompatible with ULSD because both are oxidative catalysts that will accelerate the formation of sediments, gels, and soaps. In response to this concern, Engineering determined the fuel oil piping should be replaced with a compatible material so that no structural degradation or potential fuel supply blockages occur due to the known interactions of copper and ULSD fuel. Replacement of the copper fuel oil lines with stainless steel lines is planned for installation in the near future.
5. In July 2014, prior to periodic testing of the security diesel generator, water and sediment were found in two independent 500 ml fuel oil samples of the 8-gallon security diesel generator fuel oil day tank. An Engineering walk down and inspection of the security diesel fuel oil system noted no system discrepancies that would contribute to any water in the fuel oil system or the 8-gallon fuel oil day tank for the security diesel. Fuel oil samples were obtained to inspect for water intrusion prior to operating the security diesel. Corrective actions were taken to remove all trace amounts of water by performing a bleed and feed of the 8-gallon fuel oil day tank. Water paste readings were also obtained for the underground fuel oil storage tank that supplies the 8-gallon fuel oil day tank. No indications of water were identified, verifying the integrity of the underground tank. Based on the inspections performed, immediate corrective actions were developed and implemented, and the security diesel was operated without issue.

6. From November 2014 through October 2015, the fuel oil tank inspections for initial license renewal have been completed during the 10 years prior to the period of extended operation. The inspection results for the tanks within the Fuel Oil Chemistry program are as follows:
    - Emergency diesel generator fuel oil day tanks - The '1H', '1J', and '2H' EDG fuel oil day tanks were examined by taking ultrasonic thickness measurements. Examinations for all tanks were conducted with spot ultrasonic thickness measurements taken at one-foot intervals and around tank nozzles where accessible on the exterior of the tanks. Minimum thickness values recorded for all three tanks were above nominal; therefore, there was no indication of material loss. As a result, no additional inspections or examinations were identified as being required during the period of extended operation. As noted previously, the original carbon steel '2J' EDG fuel oil day tank was replaced with a stainless steel tank in 2011. Since this stainless steel tank was installed after the issuance of the renewed license, it did not require inspection.
    - SBO diesel generator fuel oil day tank - The SBO diesel generator fuel oil day tank examination consisted of ultrasonic thickness measurements. Examinations for the tank were conducted with spot measurements taken on the exterior at one-foot intervals and around tank nozzles where accessible. Data recorded for the tank was close to or above nominal; therefore, there was negligible indication of material loss. As a result, no additional inspections or examinations were identified as being required during the period of extended operation.
    - Security diesel generator fuel oil day tank - For the security diesel generator fuel oil day tank, measurements were obtained from the exterior on the bottom plate, walls and top plate. Measurements on the walls were obtained near the bottom, middle and top. Measurements on each plate were consistent, with some differences between plates. The examination did not reveal any significant degradation; however, an additional inspection was recommended in 10 years to verify there is no degrading trend. The additional inspection is scheduled for 2024.
    - Security diesel generator fuel oil supply tank - The original carbon steel security diesel generator fuel oil supply tank was replaced in January 2015 with a double-wall fiberglass tank. As a result, the tank was considered newly installed (after issuance of the renewed license) and no inspection or examination was performed for license renewal.
    - Diesel-driven fire pump 2 fuel oil storage tank - The diesel-driven fire pump 2 fuel oil storage tank was examined. The examination consisted of ultrasonic thickness measurements using spot measurements taken on the exterior at 1-foot intervals and around tank nozzles where accessible. The majority of the data recorded was close to nominal thickness. The results indicate minimal material loss on the tank shell, ends and near nozzle locations. Using the 1/16” corrosion allowance, the projected service life of the tank would remain acceptable. As a result, no additional inspections or examinations were identified as being required during the period of extended operation.

7. In November 2015, an assessment of the Fuel Oil Chemistry program was performed. Several changes have taken place in the industry related to diesel fuel, such as reduction of sulfur content, the introduction of biodiesel into the market place, and the changes in ASTM testing methods for diesel fuel of various formulations. This assessment evaluated these changes against the current program. The assessment team confirmed procedures meet the licensing document commitments for each station. Needed program enhancements were identified which would strengthen the program.

8. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

9. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the Fuel Oil Chemistry AMA (UFSAR Section 18.2.8) related to the Fuel Oil Chemistry program.

10. In April 2019, an effectiveness review was performed on the Fuel Oil Chemistry AMA (UFSAR Section 18.2.8) that includes “Perform Aging Management Program Effectiveness Review for Fuel Oil Chemistry” among its inspection activities. The AMA was evaluated against the performance criteria identified in NEI 14-12, “Aging Management Program Effectiveness.” No gaps were identified by the effectiveness review related to the Fuel Oil Chemistry AMA.

The above examples of operating experience provide objective evidence that the *Fuel Oil Chemistry* program includes activities to perform control of chemistry parameters to manage cracking or blistering, flow blockage, hardening or loss of strength, loss of material, and reduction of heat transfer, and to perform visual inspection of tanks, and thickness measurements of tank bottoms to identify loss of material for fuel oil tanks within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Fuel Oil Chemistry* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Fuel Oil Chemistry* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Fuel Oil Chemistry* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.19 Reactor Vessel Material Surveillance

Program Description

The *Reactor Vessel Material Surveillance* program is an existing condition monitoring program that manages reduction of fracture toughness of the ferritic reactor vessel beltline materials, in accordance with the version of ASTM E185 available and used during fabrication of the reactor vessels. The program provides sufficient material to monitor reduction of fracture toughness due to neutron irradiation embrittlement until the end of the subsequent period of extended operation, and determine the need for operating restrictions on the irradiation temperature (i.e., cold leg operating temperature), neutron spectrum, and neutron fluence.

The *Reactor Vessel Material Surveillance* program was developed by Westinghouse Electric Company prior to 10 CFR 50, Appendix H. The *Reactor Vessel Material Surveillance* program consists of two elements. The first element is related to the number of capsules, location of capsules, and content of specimens. The second element is related to the test methods and schedule for testing. For the first element, related to the design of the program, WCAP-8771, “Virginia Electric and Power Co. North Anna Unit No. 1 Reactor Vessel Radiation Surveillance Program,” and WCAP-8772, “Virginia Electric and Power Co. North Anna Unit No. 2 Reactor Vessel Radiation Surveillance Program,” documented the program. The *Reactor Vessel Material Surveillance* program for Units 1 and 2 meet ASTM E185-73. Initially, the requirements relating to the testing method were not mandated by the NRC through a particular version of ASTM E185. Therefore, when a capsule was removed from the reactor vessel, it was customary at the time to document which version of ASTM E185 was used for testing. Over time, the NRC began the process of approving various editions of ASTM E185 for testing. To date, for testing and schedule considerations, the NRC has approved three editions of ASTM E185-73, -79, and -82. Currently, the *Reactor Vessel Material Surveillance* program complies with ASTM E185-82 for testing and scheduling. The withdrawal schedule in Table 1 of ASTM E185-82 is based on plant operation during the original 40-year initial license term. Standby capsules ensure appropriate monitoring during the subsequent period of extended operation. The Reactor Vessel Material Surveillance program includes removal and testing of at least one capsule, with a neutron fluence of the capsule between one and two times the projected peak vessel neutron fluence at the end of the subsequent period of extended operation. If a capsule meeting this criterion has not been tested previously, then at least one capsule will be removed and tested during the subsequent period of extended operation (or earlier) to meet this criterion.

Data from the *Reactor Vessel Material Surveillance* program is used to monitor neutron irradiation embrittlement of the reactor vessel, and is provided as input to the neutron embrittlement time limited aging analyses (TLAAs) described in Section 4.2.

In accordance with 10 CFR 50, Appendix H, all surveillance capsules, including those previously removed from the reactor vessel, must 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 in the *Reactor Vessel Material Surveillance* program or extension of the program for the subsequent period of extended operation, are required to be submitted to the Nuclear Regulatory Commission for approval prior to implementation, in accordance with 10 CFR 50, Appendix H, Paragraph III.B.3. Standby capsules placed in storage (e.g., removed from the reactor vessel) are maintained for possible future re-insertion. If one or more capsules will not be maintained in such a way as to permit future insertion, then the NRC will be notified of the change.

There were eight reactor vessel (RV) capsules installed in each RV prior to plant start up. Eight capsules is more than the minimum recommended by ASTM E185-73 or ASTM E185-82. The capsules contain representative RV material specimens, neutron dosimeters, and thermal monitors. Withdrawn capsules from each RV have been tested. One of the remaining untested capsules in each RV will be tested during the initial period of extended operation. It is envisioned that one of the remaining untested standby capsules in each RV may also be tested for asset management considerations during the subsequent license renewal period. The remaining untested standby capsules in each RV are available to satisfy potential fluence monitoring requirements during the 20-year subsequent period of extended operation.

Three capsules have been withdrawn and tested from the Unit 1 RV (V, U and W). For the initial period of extended operation, Unit 1 has one untested capsule (Capsule X) which, at its scheduled withdrawal date, will be irradiated greater than the projected peak neutron fluence of 7.20 x 10^{19} n/cm^2 (E>1.0 MeV), based upon 72 EFPY at the end of the 80-year subsequent period of extended operation. Capsule X is scheduled to be pulled in the 60-year initial period of extended operation during the refueling outage nearest to but following when the reactor vessel reaches 39.1 EFPY (tentatively the 2025 Unit 1 Refueling Outage). As scheduled, Capsule X is estimated to be irradiated to greater than 7.20 x 10^{19} n/cm^2 (E>1.0 MeV), which would be between one and two times the projected peak vessel neutron fluence at the end of the 80-year subsequent period of extended operation. Testing of Capsule X in 2025 will satisfy the initial license renewal schedule for Unit 1. Based upon the transition temperature shift (the mean value of the adjustment or shift in reference temperature for nil-ductility transition caused by irradiation) of >100°F but <200°F, only four Unit 1 capsules are required for testing per ASTM E185-82.

Four untested capsules (including standby capsules) remaining in the Unit 1 RV will be available to satisfy potential fluence monitoring requirements during the 80-year subsequent period of extended operation. Unit 1 will have three untested capsules (Capsules Z, Y, and T) irradiated in excess of the 80-year projected peak neutron fluence of 7.20 x 10^{19} n/cm^2 (E>1.0 MeV) during the subsequent period of extended operation. The fourth untested capsule (Capsule S) will not reach a neutron fluence of 7.20 x 10^{19} n/cm^2 (E>1.0 MeV) during the subsequent period of extended operation.

The following irradiation values are estimated at the end of the initial period of extended operation (50.3 EFPY):

- Capsule Z is estimated to be irradiated to 7.37 x 10^{19} n/cm^2 (E>1.0 MeV)
- Capsule Y is estimated to be irradiated to 6.48 x 10^{19} n/cm^2 (E>1.0 MeV)
- Capsule T is estimated to be irradiated to 5.77 x 10^{19} n/cm^2 (E>1.0 MeV)
- Capsule S is estimated to be irradiated to 3.74 x 10^{19} n/cm^2 (E>1.0 MeV)

An 80-year projected peak neutron fluence irradiation of 7.20 x 10^{19} n/cm^2 (E>1.0 MeV) is estimated to be attained by standby Capsules Z, Y, and T in 2036, 2043, and 2049, respectively, during the subsequent period of extended operation.

Three capsules have been withdrawn and tested from the Unit 2 RV (V, U and W). For the initial period of extended operation, Unit 2 has one untested capsule (Capsule X) which, at its scheduled withdrawal date, will be irradiated greater than the projected peak neutron fluence of 7.34 x 10^{19} n/cm^2 (E>1.0 MeV), based upon 72 EFPY at the end of the 80-year subsequent period of extended operation. Capsule X is scheduled to be pulled in the 60-year initial period of extended operation during the refueling outage nearest to but following when the reactor vessel reaches 39.3 EFPY (tentatively the 2026 Unit 2 Refueling Outage). As scheduled, Capsule X is estimated to be irradiated to greater than 7.34 x 10^{19} n/cm^2 (E>1.0 MeV), which would be between one and two times the projected peak vessel neutron fluence at the end of the 80-year subsequent period of extended operation. Testing of Capsule X in 2026 will satisfy the initial license renewal schedule for Unit 2. Based upon the transition temperature shift (>100°F but <200°F), only four Unit 2 capsules are required for testing per ASTM E185-82.

Four untested capsules (including standby capsules) remaining in the Unit 2 RV will be available to satisfy potential fluence monitoring requirements during the 80-year subsequent period of extended operation. Unit 1 will have three untested capsules (Capsules Z, Y, and T) irradiated in excess of the 80-year projected peak neutron fluence of 7.34 x 10^{19} n/cm^2 (E>1.0 MeV) during the subsequent period of extended operation. The fourth untested capsule (Capsule S) will not reach a neutron fluence of 7.34 x 10^{19} n/cm^2 (E>1.0 MeV) during the subsequent period of extended operation.

The following irradiation values are estimated at the end of the initial period of extended operation (52.3 EFPY):

- Capsule Z is estimated to be irradiated to 8.44 x 10^{19} n/cm^2 (E>1.0 MeV)
- Capsule Y is estimated to be irradiated to 6.82 x 10^{19} n/cm^2 (E>1.0 MeV)
- Capsule T is estimated to be irradiated to 6.19 x 10^{19} n/cm^2 (E>1.0 MeV)
- Capsule S is estimated to be irradiated to 3.59 x 10^{19} n/cm^2 (E>1.0 MeV)

An 80-year projected peak neutron fluence irradiation of 7.34 x 10^{19} n/cm^2 (E>1.0 MeV) is estimated to be attained by standby Capsules Z, Y, and T in 2032, 2044, and 2049, respectively, during the subsequent period of extended operation.

The Surveillance Capsule Withdrawal Schedules are depicted in the following tables:

Table B2.1.19-1, Surveillance Capsule Withdrawal Schedule for North Anna Unit 1, and

Table B2.1.19-2, Surveillance Capsule Withdrawal Schedule for North Anna Unit 2.

As part of Operating Experience consistent with statements in Regulatory Guide 1.99, Revision 2, Dominion considers the use of surveillance data from other sources when they become available. As such, information from surveillance capsules withdrawn from sister plant (Sequoyah) vessels is used to supplement information from the *Reactor Vessel Material Surveillance* program subject to the credibility limitations stated in Regulatory Position 2.1 and 2.2 of Regulatory Guide 1.99, Revision 2.

The *Reactor Vessel Material Surveillance* program is also used in conjunction with the *Neutron Fluence Monitoring* program (B3.2) which monitors neutron fluence for reactor vessel components and reactor vessel internal components

The *Reactor Vessel Material Surveillance* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *Reactor Vessel Material Surveillance* program is an existing program that is consistent with NUREG-2191, Section XI.M31, Reactor Vessel Material Surveillance.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Reactor Vessel Material Surveillance* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. Master Integrated Reactor Vessel Surveillance Program (MIRVSP) - Dominion Energy is a member of the Babcock and Wilcox Owner's Group Reactor Vessel Working Group (RVWG), and while not required, participates (along with Duke Energy, Entergy, Exelon, FirstEnergy, Florida Power and Light, and NextEra) in the RVWG's Master Integrated Reactor Vessel Surveillance Program (MIRVSP). The MIRVSP integrates the plant specific reactor vessel surveillance programs of the participants, the existing supplemental B&W Owners Group irradiation capsules, and additional supplemental irradiation capsules to assure the availability of high fluence and thermal annealing data for the participants' reactor vessels. One objective of the MIRVSP is to maximize the effectiveness of data sharing among participants to assure that required data is available to the participants for current and extended plant operation.
2. In September 1998, Unit 1 Capsule W Withdrawal and Test: Per BAW 2356, "Analysis of Capsule W, Virginia Power North Anna Unit No. 1 Nuclear Power Station Reactor Vessel Material Surveillance Program," the specimens in Unit 1 Capsule W were exposed to fluences equivalent to approximately 14.8 EFPY, 2.052 x 10^{19} n/cm^2 based on the calculated fluence, and satisfy the upper shelf energy criterion and the pressurized thermal shock reference temperature screening criteria. The adjusted reference temperatures have been shown to be less than those used in the Unit 1 P-T limit curves, thereby demonstrating margin in the operating limits. Just prior to withdrawal and testing of Capsule W, new P-T curves were submitted and NRC approval was obtained, based upon the data for Forging 03 being credible.

   Credibility, as defined in 10 CFR 50.61, and outlined in Regulatory Guide 1.99, Revision 2, is judged against the following criteria:

   a. Materials in the capsules should be those judged most likely to be controlling with regard to radiation embrittlement.
   b. Scatter in the plots of Charpy energy versus temperature for the irradiated and unirradiated conditions should be small enough to permit the determination of the 30 ft-lbs temperature and upper-shelf energy unambiguously.
   c. When there are two or more sets of surveillance data from one reactor, the scatter of ΔRT_{NDT} values about a best-fit line drawn as described in Regulatory Position 2.1 normally should be less than 28°F for welds and 17°F for base metal. Even if the fluence range is large (two or more orders of magnitude), the scatter should not exceed twice those values. Even if the data fail this criterion for use in shift calculations, they may be

credible for determining decrease in upper-shelf energy if the upper shelf can be clearly determined, following the definition given in ASTM E185-82.

d. The irradiation temperature of the Charpy specimens in the capsule should match the vessel wall temperature at the cladding/base metal interface within +/- 25°F.

e. The surveillance data for the correlation monitor material in the capsule should fall within the scatter band of the database for that material.

However, the data for Forging 03 was determined to be non-credible preparation of WCAP-18364-NP and WCAP-18363-NP in support of NAPS SLR. But while the data for Forging 03 was non-credible, it is conservative. When surveillance data is deemed non-credible per Regulatory Guide 1.99, Generic Letter 92-01 guidance considers the surveillance data to still be applicable for characterizing the beltline material through the direction of its use with a full margin term (σ_Δ) to establish the Position 2.1 RT_{NDT} when the Position 1.1 chemistry factor is concluded to be non-conservative based on that same data. The lesser of the Regulatory Guide 1.99, Revision 2, Position 1.1. and 2.1 chemistry factors is used with a full margin term for evaluation of the reactor vessel beltline material when one or more of the surveillance data fall outside of the Position 2.1 chemistry factor trend line by more than one times σ_Δ (data is non-credible), and none of the surveillance data fall more than two times σ_Δ above the Position 1.1 chemistry factor trend line (Position 1.1 chemistry factor is conservative). This determination is documented in WCAP-18363, Appendix I. (See associated description in operating experience #9, below.)

3. In August 2000, Unit 2 Capsule W Withdrawal and Test: Per BAW 2376, “Analysis of Capsule W, Virginia Power North Anna Unit No. 2 Nuclear Plant Reactor Vessel Material Surveillance Program,” the specimens in Unit 2 Capsule W were exposed to fluences equivalent to approximately 15.1 EFPY, 2.092 x 10^{19} n/cm^2 based on the calculated fluence, and satisfy the upper shelf energy criterion and the pressurized thermal shock reference temperature screening criteria. The adjusted reference temperatures have been shown to be less than those used in the Unit 2 P-T limit curves, thereby demonstrating margin in the operating limits.

4. In January 2012, a condition report was submitted to document the receipt of a “Needed” requirement issued by the EPRI Materials Reliability Program (MRP) per NEI-03-08. MRP-326, Revision 0, “Coordinated PWR Reactor Vessel Surveillance Program” was issued on December 20, 2011. The required action was to amend the surveillance capsule withdrawal schedule and obtain NRC review and approval. The specific change was for Unit 1 Capsule X to be withdrawn in 2025 instead of Capsule Z being withdrawn in 2030. The submittal was to be transmitted to the NRC no earlier than October 20, 2012, nor later May 20, 2013. The “needed” requirement was rescinded by EPRI/MRP in their letter, “Interim Guidance regarding Capsule Test Recommendations for North Anna 1 and Surry 2 in Materials Reliability Program: Coordinated PWR Reactor Vessel Surveillance Program (CRVSP) Guidelines (MRP-326),” August 14, 2012. (See OE #5 below.)

5. In April 2012, a condition report was submitted to document that after MRP-326 was originally issued, EPRI MRP voted on and agreed to issue, "Interim Guidance for Materials Reliability Program: Coordinated PWR Reactor Vessel Surveillance Program (CRVSP) Guidelines (MRP-326) Needed Guidance." The impact of the Interim Guidance was that: As an acceptable alternative, Unit 1 may maintain its existing *Reactor Vessel Material Surveillance* program withdrawal schedules and does not need to submit a schedule change request. There were no fleet actions required by either MRP-326 or the Interim Guidance since the Interim Guidance eliminates the need to revise the surveillance capsule withdrawal schedules for Unit 1. (See OE #4 above.)

6. In March 2014, Westinghouse issued letter MCOE-LTR-14-17, "Applicability of the Pressure-Temperature Limit Curve Figures During Vacuum Refill of the RCS in Mode 5 for Westinghouse and CE NSSS Plants." The P-T curves were revised and transmitted to the NRC for review and approval. The NRC issued a request for additional information (RAI) on the fluence projections to the nozzle materials located outside the traditional beltline region. As part of the RAI resolution process an update to the capsule withdrawal schedule to capture updated fluence and lead factor information was proposed under letter, "Virginia Electric and Power Company (Dominion Energy Virginia) North Anna Power Station Units 1 and 2 Revised Reactor Vessel Materials Surveillance Capsule Withdrawal Schedules," November 25, 2019 (ADAMS Accession No. ML19329C748).

7. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal aging management AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

8. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the Reactor Vessel Integrity Management AMA (UFSAR Section 18.2.14).

9. In April 2019, an effectiveness review was performed on the Reactor Vessel Integrity Management AMA (UFSAR Section 18.2.14). The AMA was evaluated against the performance criteria identified in NEI 14-12, "Aging Management Program Effectiveness." Gaps were identified by the effectiveness review related to:

- The basis for the current P-T limits in the Technical Specifications (TS) included consideration of data from two surveillance capsules for Unit 1 that was determined to be credible. However, shortly after the basis was developed, a third surveillance capsule was withdrawn and tested. The results of the three surveillance capsules together were non-credible. During evaluation of the reactor vessel integrity TLAA for subsequent license renewal, Westinghouse performed an updated credibility analysis and confirmed that the surveillance data is non-credible and documented this in a draft report. Since the data was non-credible, this data was not utilized in the calculations of Adjusted Reference Temperature (ART), consistent with NRC guidance. Instead, the Regulatory Guide 1.99, Revision 2, Position 1.1, method was utilized, resulting in a notably higher limiting ART. Since the limiting ART is a key input to P-T limit curves, this increase in ART reduced the applicability of the Unit 1 P-T limits curves from 50.3 effective full power years (EFPY) to 41 EFPY. The P-T limit curves themselves (i.e., allowable pressure and temperatures) were unchanged by this draft evaluation. Only the term to which these curves are applicable was updated. (Unit 1 has not yet reached 41 EFPY of operation and is projected to reach this point in approximately 2027.) Subsequently, through the SLR project, it was determined that while the data was non-credible, it is conservative. When surveillance data is deemed non-credible per Regulatory Guide 1.99, Generic Letter 92-01 guidance considers the surveillance data to still be applicable for characterizing the beltline material through the direction of its use with a full margin term (σ_Δ) to establish the Position 2.1 RT_{NDT} when the Position 1.1 chemistry factor is concluded to be non-conservative based on that same data. The lesser of the Regulatory Guide 1.99, Revision 2, Position 1.1. and 2.1 chemistry factors is used with a full margin term for evaluation of the reactor vessel beltline material when one or more of the surveillance data fall outside of the Position 2.1 chemistry factor trend line by more than one times σ_Δ (data is non-credible), and none of the surveillance data fall more than two times σ_Δ above the Position 1.1 chemistry factor trend line (Position 1.1 chemistry factor is conservative). This determination is documented in WCAP-18363, Appendix I, and the results show that the existing P-T curves are good through 80 years (subject to no other changes).
- During a phone call in March 2014, the NRC indicated that Surry Power Station was operating in compliance with the Technical Specifications (TS), but that clarification of the P-T curves was required to be fully representative of the operating conditions. The lessons learned from the previous telephone call with the NRC were applied to North Anna. The issue was that the TS needed to reflect the acceptability of operating at negative pressure for vacuum fill and that the minimum bolt-up temperature should be reflected on the TS figures. This was added to the P-T limit curves (TS Figures 3.4.3 2 and 3.4.3 3).

The above examples of operating experience provide objective evidence that the *Reactor Vessel Material Surveillance* program includes activities to perform withdrawal and testing of reactor vessel capsule specimens to manage a reduction in fracture toughness due to irradiation of the ferritic reactor vessel beltline materials, and to initiate corrective actions. Occurrences identified under the *Reactor Vessel Material Surveillance* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Reactor Vessel Material Surveillance* program will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Reactor Vessel Material Surveillance* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

Table B2.1.19-1 Surveillance Capsule Withdrawal Schedule[1] for North Anna Unit 1

Capsule Identification	Capsule Location[a]	Estimated Withdrawal EFPY/Year[b]	Insert EFPY/Year[b]	Estimated Capsule Fluence (x 10^{19})[b]
V	165°	1.1/1979	NA	0.306
U	65°	5.9/1987	NA	0.914
W	245°	14.8/1998	NA	2.05
Z	305°	16.2/2000	NA	1.52
Z	165°	NA	16.2/2000	1.52
Z	165°	NA	NA	7.37 (50.3 EFPY)
T	55°	16.2/2000	NA	1.52
T	245°	NA	16.2/2000	1.52
T	245°	NA	NA	5.77 (50.3 EFPY)
Y	295°	NA	NA	6.48 (50.3 EFPY)
S	45°	NA	NA	3.74 (50.3 EFPY)
X	285°	39.1/2025	NA	7.20

a. See UFSAR Figure 5.4-5 for original capsule installation locations.
b. Surveillance capsule neutron fluence and EFPY estimates are taken from WCAP-18015-NP. WCAP-18015-NP uses an NRC approved methodology, documented in WCAP-14040-A, that satisfies Regulatory Guide 1.190. 50.3 EFPY corresponds to the estimated cumulative core burnup at the end of the 60-year license period. Historic capsule withdrawal dates are taken from UFSAR Table 5.4-2.

1. Withdrawal schedule meets requirements of ASTM E185-82, “Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels,” July 1, 1982.

Table B2.1.19-2 Surveillance Capsule Withdrawal Schedule[1] for North Anna Unit 2

Capsule Identification	Capsule Location[a]	Estimated Withdrawal EFPY/Year[b]	Insert EFPY/Year[b]	Estimated Capsule Fluence (x 10^{19})[b]
V	165°	1.0/1982	NA	0.286
U	65°	6.2/1989	NA	0.985
W	245°	15.1/1999	NA	2.08
Z	305°	15.1/1999	NA	1.45
Z	165°	NA	15.1/1999	1.45
Z	165°	NA	NA	8.44 (52.3 EFPY)
T	55°	15.1/1999	NA	1.45
T	65°	NA	15.1/1999	1.45
T	65°	NA	NA	6.19 (52.3 EFPY)
Y	295°	NA	NA	6.82 (52.3 EFPY)
S	45°	NA	NA	3.59 (52.3 EFPY)
X	285°	39.3/2026	NA	7.34

a. See UFSAR Figure 5.4-5 for original capsule installation locations.
b. Surveillance capsule neutron fluence and EFPY estimates are taken from WCAP-18015-NP. WCAP-18015-NP uses an NRC approved methodology, documented in WCAP-14040-A, that satisfies Regulatory Guide 1.190. 52.3 EFPY corresponds to the estimated cumulative core burnup at the end of the 60-year license period. Historic capsule withdrawal dates are taken from UFSAR Table 5.4-2.

1. Withdrawal schedule meets requirements of ASTM E185-82, “Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels,” July 1, 1982.

B2.1.20 One-Time Inspection

Program Description

The *One-Time Inspection* program is a new condition monitoring program that will manage cracking, loss of material, and reduction of heat transfer of components containing fuel oil, lubricating oil, reactor coolant, secondary water, air, condensation, or treated borated water environments.

The *One-Time Inspection* program will conduct one-time inspections of susceptible locations to verify the effectiveness of the *Water Chemistry* program (B2.1.2), the *Fuel Oil Chemistry* program (B2.1.18), and *Lubricating Oil Analysis* program (B2.1.26). For steel components exposed to environments that do not include corrosion inhibitors, the *One-Time Inspection* program will verify that long-term loss of material will not result in a loss of intended function by performing wall thickness measurements on a representative sample of components in each environment.

The program will identify inspection locations that are isolated from the flow stream, that are stagnant, or have low flow for extended periods and are susceptible to the gradual accumulation or concentration of agents that promote certain aging effects. A representative sample size of 20% of the population (up to a maximum of 25 component inspections) will be established for each material, environment, and aging effect combination and will focus on the bounding or lead components most susceptible to aging due to time in service, and severity of operating conditions.

The program will verify either no unacceptable age-related degradation is occurring or trigger additional actions that will assure the intended function of affected components will be maintained during the subsequent period of extended operation. Technical justification of the methodology and sample size used for selecting components for one-time inspection will be documented in the One-Time Inspection Sample Basis Document.

This program will not be used for components with known age-related degradation mechanisms, or when the environment in the subsequent period of extended operation is not expected to be equivalent to that in the prior operating period. Periodic inspections will be conducted in those cases.

If any inspections do not meet the acceptance criteria, additional inspections will be conducted, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes.

The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2.

The elements of the *One-Time Inspection* program will include: (a) determination of sample size for the components to be inspected based on an assessment of material, environment, aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the potential for the aging effect to occur; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (d) 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 subsequent period of extended operation. The monitoring methods will be effective in detecting the applicable aging effects and the frequency of monitoring will be adequate to prevent significant age-related degradation.

Inspections and tests will be performed by personnel qualified in accordance with procedures and programs to perform the specified task. ASME Code components and non-ASME Code components will be inspected using procedures consistent with the ASME Code. 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.

The *One-Time Inspection* program will perform a magnetic particle test inspection of the continuous circumferential transition cone closure weld and the accessible portions of the upper shell-to-transition cone girth weld on each steam generator (essentially 100% examination coverage of each weld) prior to the subsequent period of extended operation.

The *One-Time Inspection* program will perform sample inspections for stainless steel, nickel alloy, and aluminum alloy components exposed to any air or condensation environment prior to the subsequent period of extended operation.

The *One-Time Inspection* program will be implemented, and inspections will begin no earlier than 10 years before the subsequent period of extended operation. Inspections will be completed at least six months prior to the subsequent period of extended operation, or no later than the last refueling outage prior to the subsequent period of extended operation.

NUREG-2191 Consistency

The *One-Time Inspection* program is a new program that, when implemented, will be consistent, with NUREG-2191, Section XI.M32, One-Time Inspection.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *One-Time Inspection* program will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 2010, an internal inspection of the Unit 2 refueling water storage tank was performed. The inspection required the refueling water storage tank (RWST) to be drained and the bottom cleaned. The inspection was performed using the principles of the Low Frequency Electromagnetic Technique (LFET). A scan was performed along the perimeter of the bottom plates of the RWST, including the weir, allowing adequate assessment of degradation due to pitting. In addition to this, a scan was performed along the welds in the inspection area. Ultrasonic thickness measurements were performed on the tank bottom. Two indications were identified with the LFET. Both indications were visible topside dents, with ultrasonic thickness readings being greater than the nominal design thickness. The inspection concluded that there is no indication of age-related degradation on the Unit 2 RWST bottom.
2. In 2017, an audit was performed on the Work Control Process inspections for license renewal documented from 2007 to 2017, in accordance with Commitment 22 listed in UFSAR Table 18-1, License Renewal Commitments. The purpose of the audit was to ensure that a representative sample of in-scope component groups had been inspected and to determine the need for supplemental inspections.

   UFSAR Chapter 18, Section 18.2.19, and NUREG-1766, "Safety Evaluation Report Related to the License Renewal of North Anna Power Station, Units 1 and 2, and Surry Power Station, Units 1 and 2," indicate the Work Control Process Aging Management Activity (AMA) provides opportunities to visually inspect the surfaces (internal and external) of plant components and adjacent piping. As a result, the Work Control Process AMA was used to manage aging for various component group, material, and environment combinations. As confirmation that representative components were inspected from each component group for which the Work Control Process AMA was credited, an audit was conducted of inspections performed over a 10 year period. One-time inspection results indicative of chemistry effectiveness that were associated with treated water, steam, and reactor coolant internal environments are summarized below.

   - Inspections were performed on carbon steel valve bodies with an internal treated water environment to confirm the effectiveness of the Chemistry Control Program for Secondary Systems AMA. Visual inspections were for the loss of material in carbon steel. The inspections validated that loss of material was not significant in carbon steel valve bodies.

- Inspections were performed on carbon steel valve bodies with an internal steam environment to confirm the effectiveness of the Chemistry Control Program for Secondary Systems AMA. Visual inspections were for the loss of material in carbon steel. The inspections validated that loss of material was not significant in carbon steel valve bodies.
- Inspections were performed on stainless steel valve bodies with an internal treated water environment (reactor coolant) to confirm the effectiveness of the Chemistry Control Program for Primary Systems AMA. Visual inspections were for the loss of material and cracking in stainless steel. The inspections validated there was no cracking and that loss of material was not significant in stainless steel valve bodies.

Based on these results, it was concluded that one-time Work Control Process inspections for the Chemistry Control Program for Primary and Secondary Systems AMAs were appropriate and no additional inspections or trending were required.

On December 15, 2017, the NRC completed an IP 71003 Phase II inspection of NAPS Units 1 and 2 which included an evaluation of the implementation status of UFSAR Commitment 22 and UFSAR Section 18.2.19. The resulting inspection report concluded that based on the review of licensee actions completed at the time of this inspection and the timeliness of those actions, the licensee demonstrated completion of Commitment 22 and adequate implementation of the Work Control Process AMA.

The above examples of operating experience provide objective evidence that the *One-Time Inspection* program will include activities to perform visual inspections to identify cracking, loss of material, and reduction of heat transfer for components containing fuel oil, lubricating oil, reactor coolant, secondary water, air, condensation, or treated borated water environments within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *One-Time Inspection* program will be evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements will be provided for locations where aging effects are found. The program will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the implementation of the *One-Time Inspection* program will effectively manage aging prior to a loss of intended function. Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The implementation of the *One-Time Inspection* program will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.21 Selective Leaching

Program Description

The *Selective Leaching* program is a new condition monitoring program that will manage loss of material of the susceptible materials located in a potentially aggressive environment. The materials of construction for these components may include gray cast iron, ductile iron, and copper alloys (greater than 15% zinc).

A one-time inspection of components exposed to closed-cycle cooling water or treated water environments will be conducted when plant-specific operating experience has not revealed selective leaching in these environments. Opportunistic and periodic inspections will be conducted for raw water, waste water, soil, and groundwater environments, and for closed-cycle cooling water or treated water environments when plant specific operating experience has revealed selective leaching in these environments. A sample of 3% of the population or a maximum of ten components per population at each unit will be visually and mechanically (gray cast iron and ductile iron components) inspected. If the inspection conducted for ductile iron in the 10-year period prior to a subsequent period of extended operation (i.e., the initial inspection) meets acceptance criteria, periodic inspections do not need to be conducted during the subsequent period of extended operation for ductile iron.

Periodic destructive examinations of components for physical properties (i.e., degree of dealloying, through-wall thickness, and chemical composition) will be conducted for components exposed to raw water, waste water, soil, and groundwater environments or for closed-cycle cooling water or treated water environments when plant specific operating experience has revealed selective leaching in these environments. For sample populations with greater than 35 susceptible components at each unit, two destructive examinations will be performed for that population. In addition, for sample populations with less than 35 susceptible components at each unit, one destructive examination will be performed for that population. For opportunistic and periodic inspections, the number of visual and mechanical inspections may be reduced by two for each component that is destructively examined beyond the minimum number of destructive examinations recommended for each sample population. For one-time inspections, the number of visual and mechanical inspections may be reduced by two for each component that is destructively examined for each sample population.

For two-unit sites the periodic visual and mechanical inspections can be reduced from ten to eight because the operating conditions and history at each unit are sufficiently similar (e.g., flowrate, chemistry, temperature, excursions) such that aging effects are not occurring differently between the units. Past power up-rates were implemented for both units at approximately the same time. Historically, water chemistry conditions between the two units have been very similar. The raw water source for both units is Lake Anna. Emergency diesel generator runs are managed to equalize total run times among the diesels, so as to equalize wear and aging. Operating experience for each unit demonstrates no significant difference in aging effects of systems in the scope of this program between the two units.

Inspections will be performed by personnel qualified in accordance with 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 inspection procedures will include requirements for items such as lighting, distance, offset, and surface conditions.

Inspection results will be evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation. The acceptance criteria are:

(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, and

(d) the components meet system design requirements such as minimum wall thickness, when extended to the end of the subsequent period of extended operation.

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 subsequent period of extended operation, additional inspections will be performed. 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. Extent of condition and extent of cause analysis will include evaluation of difficult-to-access surfaces if unacceptable inspection findings occur within the same material and environment population. 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.

NUREG-2191 Consistency

The *Selective Leaching* program is a new program that, when implemented, will be consistent, with NUREG-2191, Section XI.M33, Selective Leaching.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Selective Leaching* program will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In December 2015, a buried fire protection supply isolation valve was leaking by its closed seat. The valve had a metallurgical analysis performed which identified some isolated locations of graphitic corrosion on the interior and exterior of the valve body. The corrosion had minimal impact on the valve body thickness. In March of 2016, the six-inch cast-iron valve was replaced with a new valve fabricated from ductile iron body, which has improved corrosion resistance.
2. In June 2020, a review of 2001 through 2020 operational experience for buried and underground piping susceptible to selective leaching within the scope of subsequent license renewal was performed and did not identify any loss of intended function due to selective leaching. Inspection reports did not identify internal coating failures. In addition, isolated areas of external surface degradation with no pitting or gross corrosion were observed. Metallurgical analysis performed on removed piping indicated the internal cementitious coating was intact, showing only a fine, craze surface cracking in some areas. Opportunistic or scheduled inspections noted below indicated the piping was in good condition.
    - In October 2001 a rupture of fire protection main loop piping occurred. A metallurgical analysis determined that the failure most likely occurred as a result of a low cycle fatigue process that originated at a pre-existing manufacturing flaw in the pipe. The ruptured piping was replaced.
    - In August 2011 opportunistic inspections were performed on the southside section of the fire protection main yard loop piping during system modifications. There were no signs of degradation.
    - In September 2011 opportunistic inspection of NANIC fire protection piping during modifications for North Anna 3 site separation activities was performed. The cast iron piping was in satisfactory condition, no repairs required.
    - In December 2011 opportunistic inspection of fire protection piping outside the southeast corner of the protected area during modifications for North Anna 3 site separation activities was performed. The cast iron piping was in satisfactory condition, no repairs required.
    - In September 2012 opportunistic inspection of fire protection piping during modification for the Unit 3 tie-in to main fire loop was performed. The external coating was found to be covering the pipe and not degraded by the condition. There was no bare metal observed and no signs of corrosion or pitting. The internal lining was found to be fully intact.

- In November 2012 opportunistic inspection of the fire protection pipe replacement design change, opportunistic inspection of the cast iron fire protection main loop to the auxiliary building room was performed. There were small areas of external coating degradation, no pitting was observed, and the internal mortar lining was found to be fully intact. Opportunistic inspection was also performed on a southside section of the cast iron fire protection main yard loop piping. The external coating was in good condition with no damage. The cast iron piping external surfaces did not show evidence of pitting or corrosion. The internal mortar lining was found to be fully intact and protecting the pipe.
- In May 2013, following replacement of cast iron fire main piping segments with ductile iron fire main piping, the scope of the replacement project was reduced to areas potentially challenging adjacent safety-related piping. The buried fire protection piping on the west side of the station that serves as the backup water supply to the Unit 2 auxiliary feedwater system was replaced. Also, the buried cast iron fire protection piping at the northwest and southwest tie-in connection points was replaced with ductile iron pipe. New ductile iron pipe was installed at the Southeast Security Building. The external coating was in good condition. There was no corrosion identified on the external surface. The internal cementitious lining was determined to be in good condition, fully intact, and protecting the pipe in these cases.
- In August 2015, cast iron North Yard fire protection piping from the main fire loop to the Unit 2 Turbine Building was excavated for a buried pipe inspection. The cast iron fire protection piping is internally lined with a cementitious coating and externally coated with a coal tar epoxy. Inspection required removal of a portion of the exterior coating on each pipe for visual and wall thickness examinations. Coatings were in good condition. Visual and wall thickness examinations indicated minor corrosion and pitting in a few places. There was no significant loss of material or minimum wall thickness identified. The piping was recoated prior to backfill.

The above examples of operating experience provide objective evidence that the *Selective Leaching* program will include activities to perform visual and mechanical inspections or destructive examinations to identify loss of material for piping, valve bodies and bonnets, pump casings, and heat exchanger components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Selective Leaching* program will be evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements will be provided for locations where aging effects are found. The program will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the implementation of the *Selective Leaching* program will effectively manage aging prior to a loss of intended function. Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The implementation of the *Selective Leaching* program will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.22 ASME Code Class 1 Small-Bore Piping

Program Description

The *ASME Code Class 1 Small-Bore Piping* program is a new condition monitoring program that will manage cracking of ASME Code Class 1 small-bore piping that is defined as greater than or equal to one inch nominal pipe size (NPS) and less than four inches NPS. This program will utilize volumetric or destructive examinations to augment examinations performed by the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1).

The ASME Code Class 1 Small-Bore Piping program will focus on socket and butt welds for piping that is susceptible to stress corrosion cracking (SCC), and cracking due to thermal or vibratory fatigue loading. One-time inspections and periodic inspections will determine the presence of cracking for locations within the scope of the ASME Code Class 1 Small-Bore Piping program including full penetration (butt) and partial penetration (socket) welds.

<u>Butt Welded Piping</u>

Age-related cracking has been experienced in both Units 1 and 2 reactor coolant system cold leg drain butt-welded piping. Corrective actions have been taken to mitigate the risk of age-related cracking and the cause has been partially mitigated with changing the locations from which reactor coolant is sampled by Chemistry. However, since swirl penetration has been identified as a possible contributor to the cracking, the cause of the cracking has not been fully mitigated. Therefore, based on NUREG-2191, Table XI.M35-1, since age-related cracking has occurred in butt welded piping for both units, and since the cause of cracking has not been fully mitigated, Category C criteria is required for performing periodic inspections of small-bore butt welds for both units. Accordingly, for each unit, periodic volumetric or destructive inspections of susceptible butt welds will be performed with the first examinations completed within the six-year period prior to the subsequent period of extended operation and subsequent examinations completed every 10 years during the subsequent period of extended operation.

<u>Socket Welded Piping</u>

With the exception of the reactor coolant pump (RCP) seal injection-thermal barrier (SI-TB) nozzle welds (discussed below), age-related cracking has not been identified in Class 1 small-bore socket welded piping. Category A criteria is required for examination of Class 1 small-bore socket welds for both units. A one-time inspection of a sample of socket welds will be performed on each unit with the examinations completed within the six-year period prior to the subsequent period of extended operation. The examination method will be volumetric or destructive with welds selected for examination from locations determined to be most risk significant and most susceptible to cracking. Each socket weld subject to destructive examination may be credited twice toward the total number of examinations. Should evidence of cracking be revealed by a one-time inspection, a periodic inspection consistent with Category C criteria is required.

RCP Seal Injection-Thermal Barrier (SI-TB) Nozzle Socket Welds

The RCP seal injection line has a pipe stub directly connected to the thermal barrier casing and is flanged at the other end to mate up with the seal injection line from the chemical and volume control system. This injection pipe stub connects to the thermal barrier casing with a factory installed socket weld. There are also two capped pressure taps (no longer used) with factory installed socket welds on each RCP. There are only nine of these ASME Code Class 1 socket welds per unit that constitute a unique subset within the small-bore socket weld population.

The plant has experienced cracking in two of the six factory designed RCP SI-TB nozzle welds. The six RCP internals are scheduled for replacement prior to the subsequent period of extended operation. Due to these cracks of the factory designed SI-TB nozzle welds, modifications to the original factory thermal barrier nozzle welds utilizing an improved weld design are currently being considered during RCP internals replacements. Weld improvements include a deeper partial penetration weld, wider “J” groove bevel, increased insertion depth, and a limited diametrical clearance. Replacement of the original SI-TB nozzle welds with the improved design will mitigate the cause of cracking that occurred in 1994 and 2020.

Without modification to the new weld design, the thermal barrier nozzle welds are Category C per NUREG-2191, Table XI.M35-1. Since the new weld design is intended to mitigate the cause of cracking in the thermal barrier nozzle welds, upon complete replacement, the new thermal barrier nozzle welds will meet the requirements for Category B per NUREG-2191, Table XI.M35-1. Therefore, the thermal barrier nozzle welds for each unit will be inspected to the Category C requirements until thermal barrier nozzle welds are replaced with the improved weld design. For each unit, when all thermal barrier nozzle welds have been replaced with the improved weld design, Category B inspection requirements will then be applicable.

The following table provides a summary of the number of one-time inspections and periodic inspections required for Unit 1 and Unit 2 socket welds and butt welds:

Unit	Weld Type	Table XI.M35-1 Category	Examination Schedule	Total Weld Population	Sample Size
1	Socket	A	One-time: completed within 6 years prior to the start of the subsequent period of extended operation	700+	10 (3%, up to 10 max.)
	Butt	C	Periodic: first examination completed within the 6 years prior to the start of the subsequent period of extended operation with subsequent examinations every 10 years thereafter	500+	25 (10%, up to 25 max.)
	Socket (RCP thermal barrier nozzles)	B (see Note 1)	One-time: completed within 6 years prior to the start of the subsequent period of extended operation	9	1 (10%, up to 25 max.)
		C (see Note 2)	Periodic: first examination completed within the 6 years prior to the start of the subsequent period of extended operation with subsequent examinations every 10 years thereafter	9	1 (10%, up to 25 max.)
2	Socket	A	One-time: completed within 6 years prior to the start of the subsequent period of extended operation	900+	10 (3%, up to 10 max.)
	Butt	C	Periodic: first examination completed within the 6 years prior to the start of the subsequent period of extended operation with subsequent examinations every 10 years thereafter	500+	25 (10%, up to 25 max.)
	Socket (RCP thermal barrier nozzles)	B (see Note 1)	One-time: completed within 6 years prior to the start of the subsequent period of extended operation	9	1 (10%, up to 25 max.)
		C (see Note 2)	Periodic: first examination completed within the 6 years prior to the start of the subsequent period of extended operation with subsequent examinations every 10 years thereafter	9	1 (10%, up to 25 max.)
Note 1: Category B will apply if all Class 1 RCP thermal barrier nozzle welds have been replaced with the improved design. For this case, a one time phased array UT inspection will be performed on the oldest redesigned SI-TB weld installed in each unit. Note 2: Category C will apply if original RCP thermal barrier nozzle weld design is still in use. For this case periodic phased array UT inspections will be performed on the original SI-TB nozzle welds.					

NUREG-2191 Consistency

The ASME Code Class 1 Small-Bore Piping program is a new program that, when implemented, will be consistent, with NUREG-2191, Section XI.M35, ASME Code Class 1 Small-Bore Piping.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *ASME Code Class 1 Small-Bore Piping* program will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In June 1994, a leak was identified at the nozzle weld on the 1.5 inch seal injection line entering the Unit 2 'B' RCP thermal barrier housing. Repairs to the SI-TB nozzle weld were completed in accordance with the ASME Section XI Repair / Replacement Program. Liquid Penetrant (LP) examinations were performed on the SI-TB nozzle weld and on the two remaining Unit 2 RCP SI-TB nozzle welds with satisfactory results. LP examinations were also performed on the nozzle welds for the component cooling supply and return lines for all three RCPs. The results of the LP examinations confirm that there were no surface indications which could initiate a crack at any of the nozzle welds. In addition, the piping supports for the Unit 2 'B' RCP seal injection line were inspected and adjusted to verify that they were consistent with the initial plant design. The SI-TB nozzle weld was repaired using the improved vendor design which was current at the time of the repair for the pipe to nozzle weld. This in conjunction with the adjustment of the seal injection line support were deemed sufficient to preclude recurrence. The root cause of the Unit 2 RCP SI-TB nozzle weld failure was hypothesized to be material condition. The most likely scenario is that crack initiation was due to a minor weld defect or geometric discontinuity, such as an area of undercut at the toe of the weld, and the presence of high mean stress which was driven intermittently causing accumulation of damage. The failure mechanism has been classified as high cycle, variable stress amplitude mechanical fatigue. The crack propagated from the flaw in the weld through the weld material and into the thermal barrier housing casing. Eventually, the crack propagated to such a point that the local primary stress was too great, resulting in pressure boundary leakage. A probable contributor to the failure was identified as the nozzle weld profile. Undocumented grinding had previously occurred on the nozzle weld that failed. It is possible that an attempt had been made to grind out a defect. In addition, this grinding effectively changed the weld profile to one that is more susceptible to fatigue failure. Possible contributors to the weld failure were

identified as higher than normal vibrations and residual stresses induced during the manufacture and construction processes.

2. In April 2009, during the Beaver Valley Unit 1 refueling outage, while performing planned ultrasonic examination of reactor coolant piping in accordance with MRP-146, "Materials Reliability Program: Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines," two relevant indications were found in a reactor coolant system 2-inch pipe segment which is a stainless steel drain/sample line off of the 'A' loop hot leg. This industry operating experience was reviewed and evaluated by Engineering which resulted in program improvements. Specifically, augmented inspection activities were revised to incorporate this industry operating experience by extending the examination volume for applicable down horizontal (DH) locations.
3. In December 2014, a pressure boundary leak was discovered at the Unit 1 'B' reactor coolant loop cold leg drain line elbow. The elbow was replaced and the failed elbow/piping provided for materials failure analysis. The failure analysis indicated the failure occurred due to fatigue resulting in a through-wall axial crack in the elbow and circumferential oriented cracks on both sides of the butt weld. The two main contributors to this failure were determined to be swirl penetration and the use of these lines for chemistry sampling. As a result of this event, UT examinations were performed on all remaining Unit 1 and Unit 2 reactor coolant loop hot leg and cold leg drain line elbows. During these examinations, a relevant indication was found in a Unit 1 'C' reactor coolant loop cold leg drain line elbow. However, follow-up destructive examinations on the elbow did not reveal any service induced flaws. As a result of this operating experience, a manual phased array ultrasonic examination technique has been incorporated into Dominion Fleet procedures as a contingency in the event relevant indications are identified during the standard manual UT examination of the loop drain piping. Also, the scope and frequency of reactor coolant loop hot leg and cold leg drain line examinations were updated based on examination results. In addition, chemistry sampling procedures were updated to incorporate fleet best practices to collect routine samples from letdown lines instead of sampling directly from the RCS cold leg drain lines.
4. In March 2016, a crack was identified in the Unit 2 'A' reactor coolant loop cold leg drain line elbow butt weld. The elbow weld was being examined to satisfy MRP-146 examination requirements and was required as a corrective action due to the December 2014 leak at the Unit 1 'B' reactor coolant loop cold leg drain line elbow. A destructive examination was performed on the cracked elbow. The destructive examination report indicated the crack was likely the result of thermal fatigue, which was consistent with the Root Cause Evaluation of the December 2014 failure.

5. In March 2019, the Unit 2 'A' reactor coolant loop cold leg drain line elbow butt weld that was replaced in March 2016 was being examined to satisfy MRP-146 examination requirements. During the volumetric examination, an indication was identified at the weld root on the elbow side of the weld. Due to the history of pipe failures at similar locations, the indication was determined to be unacceptable and pipe was replaced.
6. In April 2019, the Materials Reliability Program (MRP) issued MRP 2019-008, “Interim Guidance for NEI 03-08 Needed Requirements for US PWR Plants for Management of Thermal Fatigue in Non-Isolable Reactor Coolant System Branch Lines.” Relative to small-bore piping, interim guidance includes increasing the inspection frequency of down-horizontal (DH) lines where cracking has been identified to every other refueling outage and increasing the examination volume for up-horizontal/horizontal (UH/H) lines. Engineering performed a review of interim guidance items and has confirmed all requirements have been incorporated into the program.
7. In April 2020, Operations identified a pressure boundary leakage on the SI-TB nozzle weld for the Unit 2 'A' RCP. The leak originated from a crack located at the toe of the weld (thermal barrier side) joining the seal injection line to the RCP thermal barrier. The cause of the leak has been attributed to a combination of initial weld quality, elevated nozzle loads, lack of conservatism in weld joint detail, and stresses induced by system vibration. The combination of these four causes resulted in high cycle fatigue and cracking of the welded joint connection between the seal injection line to the RCP thermal barrier. Based on evaluation from the 1994 failure, the piping support configuration, nozzle thermal moment, and design CUF suggest that the extent of cause is limited to the Unit 2 'A' and 'B' RCPs. The crack at the Unit 2 'B' SI-TB nozzle weld was repaired with the improved weld joint design in 1994. This results in an extent of cause limited to the Unit 2 'A' RCP SI-TB nozzle weld as susceptible to this failure mode cause. The Unit 2 'A' RCP SI-TB nozzle weld was repaired and additional Liquid Penetrant (LP) inspections were performed on Unit 2 'B' and 'C' RCP SI-TB nozzle welds during the 2020 forced outage. Both LP exams were completed satisfactorily with no indications of cracking or deformation noted. Additional examinations will be performed using a phased-array UT technique. An NDE volumetric inspection program of thermal barrier piping weld joints will be implemented until the welds are modified to the improved weld joint design.

The above examples of operating experience provide objective evidence that the *ASME Code Class 1 Small-Bore Piping* program will include activities to perform volumetric and visual inspections to manage cracking of ASME Code Class 1 small-bore piping within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *ASME Code Class 1 Small-Bore Piping* program will be evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements will be provided for locations where aging effects are found. The program will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the implementation of the *ASME Code Class 1 Small-Bore Piping* program will effectively manage aging prior to a loss of intended function. Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The implementation of the *ASME Code Class 1 Small-Bore Piping* program will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.23 External Surfaces Monitoring of Mechanical Components

Program Description

The *External Surfaces Monitoring of Mechanical Components* program is an existing condition monitoring program that manages the following aging effects:

- Loss of material, cracking, and reduction of heat transfer of metallic components;
- Hardening or loss of strength, loss of material, and cracking or blistering of polymeric components;
- Hardening or loss of strength, and loss of material of elastomeric components;
- Loss of material, cracking, and loss of preload of HVAC closure bolting; and
- Reduced thermal insulation resistance

Visual inspections are performed during system inspections and walkdowns. The inspection parameters for metallic components include material condition, which consists of evidence of rust, pitting, crevice, and general corrosion; surface imperfections such as cracking and wastage; coating degradation such as cracking, flaking, or blistering; evidence of insulation damage or wetting; leakage from piping, ducting, or component bolted joints; 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 blistering, hardening, discoloration, surface cracking, crazing, scuffing, loss of thickness, exposure of internal reinforcement, and dimensional changes. For certain materials, such as flexible polymers, physical manipulation to detect hardening or loss of strength is used to augment the visual inspections conducted under this program.

Periodic visual inspections, not to exceed a refueling outage interval, of metallic and polymeric components and insulation jacketing (insulation when not jacketed) are conducted. This frequency accommodates inspections of components that may be in locations that are normally only accessible during refueling outages. Surfaces that are not readily visible during plant operations and refueling outages are inspected when they are made accessible and at such intervals that would ensure the components intended functions are maintained. There are no cementitious components within the scope of this program.

ASME Code, Section XI visual examinations (VT-1) or surface examinations will be conducted to detect cracking of stainless steel, nickel-alloy, and copper alloy (>15% Zn) components exposed to aqueous solutions or aggressive air environments. A representative sample will be performed from each of the stainless steel, nickel-alloy, and copper alloy (>15% Zn) component populations every 10 years. Examinations are conducted on 20% of the surface area unless the component is measured in linear feet, such as piping. Alternatively, any combination of a minimum of 25 one-foot axial length sections and components is inspected. For each unit, both the inner and outer nickel-alloy reactor vessel flange leakage monitor tubes will be inspected every 10 years.

A sample of outdoor component surfaces that are insulated and a sample of indoor insulated components exposed to condensation (due to the in-scope component being operated below the dew point), will be periodically inspected every 10 years during the subsequent period of extended operation. Following insulation removal, ASME Code, Section XI VT-1 examinations or surface examinations will be conducted to detect loss of material and cracking of the component surfaces. 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 one-foot axial length determination is inspected. Alternatively, any combination of a minimum of 25 one-foot axial length sections and components for each material type is inspected.

If any sampling-based inspections to detect cracking in stainless steel, nickel-alloy, and copper alloy (>15% Zn) do not meet the acceptance criteria, additional inspections will be conducted, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. The additional inspections are completed within the interval (i.e., 10-year inspection interval) in which the original inspection was conducted. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2.

Inspections are performed by personnel qualified in accordance with site procedures and programs to perform the specified task. Inspections within the scope of the ASME Code follow site procedures consistent with the ASME Code. Non-ASME Code inspection procedures include requirements for items such as lighting, distance, offset, surface coverage, and presence of protective coatings.

Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the subsequent period of extended operation. For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions.

The external surfaces of components that are buried or in underground environments are inspected by the *Buried and Underground Piping and Tanks* program (B2.1.27). The external surfaces of outdoor tanks and indoor large volume metallic storage tanks (capacity >100,000 gallons) are inspected by the *Outdoor and Large Atmospheric Metallic Storage Tanks* program (B2.1.17). Loss of material due to boric acid corrosion is managed by the *Boric Acid Corrosion* program (B2.1.4).

The *External Surfaces Monitoring of Mechanical Components* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *External Surfaces Monitoring of Mechanical Components* program is an existing program that, following enhancement, will be consistent, with NUREG-2191, Section XI.M36, External Surfaces Monitoring of Mechanical Components.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Detection of Aging Effects (Element 4)

1. Procedures will be revised to specify walkdowns will be performed at a frequency not to exceed one refueling cycle. Since some surfaces are not readily visible during both plant operations and refueling outages, surfaces will be inspected when they are made accessible and at intervals that ensure the components' intended functions are maintained.
2. Procedures will be revised to specify that visual inspections of elastomers and flexible polymers will cover 100% of accessible component surfaces. The minimum surface area for tactile inspections of elastomers and flexible polymers will be at least 10% of the accessible surface area.

Detection of Aging Effects (Element 4); Corrective Actions (Element 7)

3. A new procedure will be developed to specify the following to manage cracking of stainless steel, nickel-alloy, and copper alloy (>15% Zn) components and cracking and loss of material of insulated outdoor/indoor components exposed to condensation populations:
    a. In each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed. Inspections for cracking will be performed from each of the stainless steel, nickel-alloy, and copper alloy (>15% Zn) component populations every 10 years. Examinations are conducted on 20% of the surface area unless the component is measured in linear feet, such as piping. Alternatively, any combination of a minimum of 25 one-foot axial length sections and components is inspected. In addition,

for each unit, both the inner and outer nickel-alloy reactor vessel flange leakage monitor tubes will be inspected every 10 years. For insulated outdoor components and indoor components exposed to condensation, following insulation removal, 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 one-foot axial length determination is inspected for loss of material and cracking. Alternatively, any combination of a minimum of 25 one-foot axial length sections and components for each material type is inspected. The new procedure will specify that the inspections focus on the components most susceptible to aging because of time in service, severity of operating conditions, and lowest design margin.

b. Additional inspections will be performed if any sampling-based inspections to detect cracking in stainless steel, nickel-alloy, and copper alloy (>15% Zn) components do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted.

Monitoring and Trending (Element 5) and Corrective Action (Element 7)

4. Procedures will be revised to evaluate and project the rate of degradation until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection sampling bases (e.g., selection, size, frequency) will be adjusted as necessary based on the projection.

Acceptance Criteria (Element 6)

5. Procedures will be revised to specify that, where practical, acceptance criteria are quantitative (e.g., minimum wall thickness). For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *External Surfaces Monitoring of Mechanical Components* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In January 2010, a condition report was initiated to document minor exterior cracking on an expansion joint outer cover at the discharge of the Unit 2 '1B' component cooling pump.

   Engineering walked down the expansion joint and concluded that there was no impact on the design function of the expansion joint and as-found condition was acceptable for continued service. To address long-term reliability concerns, the cover was repaired in July 2011.

2. In July 2010, while investigating an increase in Unit 1 Containment sump in-leakage, a pinhole leak and small through-wall crack were discovered on an unisolable section of insulated steam generator sample piping located under a support. The unit was shut down to perform the requisite repairs and extent of condition evaluation.

   An immediate extent of condition review identified corrosion damage on another steam generator sample line in a similar location.

   Sections of the damaged piping were removed for metallurgical analysis. The results of the metallurgical analysis attributed the cause to be external corrosion caused by long-term wetting of the insulation between the support and the affected pipe. The most likely cause of the wetted insulation was attributed to water introduced during past Containment close-out activities, when water was previously used, but is no longer employed, to clean general areas.

   To prevent similar occurrences in the future, several actions were taken:

   - An evaluation was performed to identify any additional piping at both units that may be susceptible to a similar failure.
   - A matrix of susceptible piping was created, along with recommendations for further inspections for corrosion under insulation.
   - Extent of condition inspections identified minor surface rust in a few locations. What appeared to be more significant rusting was noted on several chilled water piping segments. Follow-up ultrasonic thickness measurements were taken on these areas and revealed that all readings were close to nominal thickness. No other concerns were identified.
   - A procedure was revised to require unisolable, insulated carbon-steel piping located inside Containment to have periodic inspections performed at specified frequencies.

- System monitoring plans were revised to specify that visual inspections of insulation for damage or wetting be performed of susceptible pipe segments at least every 18 months.
- Recurring preventative maintenance tasks were created to remove the insulation and inspect for corrosion under insulation on unisolable sections of blowdown and secondary sample piping every four refueling outages.

3. In October 2011, during a Unit 2 condensate system walkdown, Engineering personnel noted loose insulation jacketing on a section of steam drain piping. A condition report was created to document the issue and a work order was completed approximately one week later to repair the jacketing.
4. In October 2011, during a walkdown, a leak was identified in the Unit 2 reactor vessel flange leak detection line from the accumulation of boric acid. The degraded section of the stainless steel tubing was replaced. Metallurgical analysis concluded that the tube cracking was most likely the result of transgranular stress corrosion cracking (TGSCC). The evidence further supports the notion that the tubing was exposed to a condition conducive to corrosion by the presence of pits along the interior surface of the tubing. Additional tubing sections from the Unit 2 reactor vessel flange leak detection lines were removed for metallurgical examination. The metallurgical investigation identified no additional stress corrosion cracking (SCC) in any of the samples removed. In addition, the microstructure of the tubing appears typical of a Class I CN9 austenitic stainless steel. The results of the metallurgical analysis indicated that the SCC that occurred in 2011 was not widespread. As such, the metallurgical samples can be considered indicative to the condition of the remaining downstream tubing. Therefore, is was concluded the likelihood that SCC has damaged or compromised the remaining sections of leak-off tubing is low. In addition, to ensure that the lines remain clear of boric acid crystals and stagnant fluid PM tasks have been created to flush the lines. Flushing of the flange leak detection lines is currently scheduled for Fall 2022 and Fall 2026 for Units 1 and 2 respectively. Based on the analysis performed, inspections performed, and the creation of PMs to flush the lines, no additional corrective actions for the Unit 1 or Unit 2 reactor leak-off lines are recommended.
5. In December 2014, during an Engineering department self-evaluation meeting, a gap was identified related to the General Condition Monitoring Activities AMA (UFSAR Section 18.2.9) walkdowns. Specifically, improvement was needed in the process for consistently documenting and recording system engineer walkdowns.

   A condition report was initiated. Corrective actions included:

   - Development and delivery of training for Engineering roles and responsibilities related to walkdowns
   - Implementation of a process for ensuring system walkdown records are maintained.

- Development of a template in the walkdown tracking database to match the specific requirements in the walkdown procedure.

A search of the Corrective Action Program database did not reveal any subsequent issues with consistently documenting and recording system engineer walkdowns since the corrective actions were implemented.

6. In March 2016, during an inspection in the pipe penetration area of the missile barrier adjacent to the Unit 2 emergency condensate storage tank, corrosion was noted on the external surfaces of several pipe segments. Condition reports for each piping segment were initiated, with the recommendation that nondestructive examination be performed to measure wall thicknesses. The wall thicknesses were determined to be very close to nominal, and well above the minimum wall thickness. A work order was completed to recoat the piping to mitigate future corrosion.

7. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion was reached that no performance deficiencies or learning opportunities were identified for the General Condition Monitoring Activities AMA (UFSAR Section 18.2.9) related to components within the scope of the External Surfaces Monitoring of Mechanical Components program for subsequent license renewal.

8. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

9. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the General Condition Monitoring Activities AMA (UFSAR Section 18.2.9) related to components within the scope of the External Surfaces Monitoring of Mechanical Components program for subsequent license renewal.

10. In December 2017, Engineering personnel noted water dripping in the Turbine Building due to a drain line for a cooler that had a through wall leak. The leak was caused by vibration induced wear between the copper tubing and a support bracket. A condition report was initiated and the damaged copper tubing was subsequently replaced.

    Engineering conducted an extent of condition review. No additional leaks were observed, however, additional pipe supports were identified to have missing fasteners. A condition report was submitted to make the required repairs.

11. In April 2019, an effectiveness review was performed on the General Condition Monitoring Activities AMP (UFSAR Section 18.2.9). The AMA was evaluated against the performance criteria identified in NEI 14-12, “Aging Management Program Effectiveness.” No gaps were identified by the effectiveness review related to components within the scope of the External Surfaces Monitoring of Mechanical Components program for subsequent license renewal.

The above examples of operating experience provide objective evidence that the *External Surfaces Monitoring of Mechanical Components* program includes activities to perform visual inspections to manage aging effects of components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *External Surfaces Monitoring of Mechanical Components* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *External Surfaces Monitoring of Mechanical Components* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *External Surfaces Monitoring of Mechanical Components* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.24 Flux Thimble Tube Inspection

Program Description

The *Flux Thimble Tube Inspection* program is an existing condition monitoring program that manages loss of material due to wear by inspecting for thinning of the flux thimble tube walls. Flux thimble tubes provide a path for the incore neutron flux monitoring system detectors and form part of the reactor coolant system pressure boundary. Flux thimble tubes are subject to loss of material at certain locations in the reactor vessel where flow-induced fretting causes wear at discontinuities in the path from the reactor vessel instrument nozzle to the fuel assembly instrument guide tube. Such discontinuities could be present in the areas of the lower core plate, the lower internals support column, and the reactor vessel penetration nozzle. Flux thimbles are a single tube design. Degradation of the flux thimble creates the potential of a non-isolable leak of the reactor coolant system and possible damage of the detectors if exposed to the reactor vessel environment conditions.

Periodic eddy current examinations are performed as an augmented inspection by the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1) to confirm the integrity of the flux thimble tubes is consistent with the recommendations of Inspection and Enforcement Bulletin 88-09 (IEB 88-09), “Thimble Tube Thinning in Westinghouse Reactors,” and WCAP-12866, “Bottom Mounted Instrumentation Flux Thimble Wear.” In response to IEB 88-09, flux thimble tubes were replaced or repositioned if 35% to 49% through-wall thinning was experienced and eddy current testing was performed every refueling for each unit. With the 1991 issuance of WCAP-12866, criterion was adopted that a wall loss of 80% would be used to determine when thimble action (i.e., repositioning, replacement, etc.) was required. In 2003, as supported by Engineering review, the acceptance criteria was tightened to use a wall loss of 70% to determine when thimble action was required. As a result of a 2013 Engineering technical evaluation, a wall loss of 80% or greater was set as the criterion for tube isolation.

Results of previous examinations are utilized to determine any trend for the extent of flux thimble tube wall thinning. For example, following the replacement of eighteen flux thimbles during the Fall 2016 Unit 1 refueling outage, a condition report was issued to review the subsequent Spring 2018 Unit 1 refueling outage eddy current results to determine if a change in testing frequency was warranted. Based on this review, Engineering concurred that the test results justified a frequency change from every refueling to every 36 months. In 2019, the Unit 1 eddy current examination procedure was modified to reflect the new 36-month frequency. The Unit 2 eddy current examination schedule remains on a frequency of every refueling outage pending accumulation and evaluation of test results justifying a frequency change. Compensatory action is taken for any tube that has a remaining wall thickness that is less than the minimum allowable, or is projected to reach minimum allowable wall thickness prior to the next inspection.

NUREG-2191 Consistency

The *Flux Thimble Tube Inspection* program is an existing program that is consistent with NUREG-2191, Section XI.M37, Flux Thimble Tube Inspection.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Flux Thimble Tube Inspection* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 2013, a Unit 2 flux thimble tube, which had been retracted three inches in 2011, was confirmed to have a wall loss of 72%. An Engineering evaluation was performed to determine if this thimble tube could be left unisolated and the conclusion was reached that no action needed to be taken (retraction or isolation) until 80% through-wall loss had occurred. A work order was initiated to replace the tube during the Fall 2014 Unit 2 refueling outage, but the work order was canceled based on a design change which resulted in the replacement of eleven Unit 2 flux thimbles in October 2017. Throughout the April 2013 to October 2017 time period, eddy-current monitoring of the tube verified that wall loss remained below the 80% acceptance criteria without the need for additional retraction.
2. In March 2016, eddy current testing indicated that a Unit 2 flux thimble tube had an active wear location where the tube wall had degraded from 48% wall loss to 75% wall loss over the course of the operating cycle. The thimble tube was already isolated based on previous wear at three other axial locations which exceeded the greater than 70% total wall loss acceptance criteria. All other wear locations had remained steady over the operating cycle. The thimble tube was retracted by 6 inches to reposition the current wear location to a different axial location on the thimble tube in the event that wear were to continue in the present active location. Based on a design change, eleven Unit 2 flux thimbles were replaced in October 2017.
3. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion was reached that no performance deficiencies or learning opportunities were identified for the Augmented Inspection Activities AMA (UFSAR Section 18.2.1) related to the inspection of flux thimble tubes.

4. In October 2016, eighteen flux thimbles were replaced in Unit 1 with new flux thimbles containing chrome plating in the area where wall thinning had typically occurred. These flux thimbles were determined to need replacement because they either had greater than or equal to 50% wall loss, had been repositioned, the detector would not pass through, or had been isolated for other reasons. Follow-up ECT during the next refueling outage identified no new damage in any of these replaced tubes.
5. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.
6. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the Augmented Inspection Activities AMA (UFSAR Section 18.2.1) related to the inspection of flux thimble tubes.
7. In October 2017, eleven flux thimbles were replaced in Unit 2 with new flux thimbles containing chrome plating in the area where wall thinning had typically occurred. These flux thimbles were determined to need replacement because they either had greater than or equal to 50% wall loss, had been repositioned, the detector would not pass through, or had been isolated for other reasons. Follow-up ECT during the next refueling outage identified no new damage in any of the replaced tubes.
8. In March 2019, as a result of incore thimble tube eddy current examination, it was identified that a Unit 2 tube had a new 47% through-wall defect that developed over the course of the previous operating cycle. The thimble tube was repositioned to ensure that any new wear to occur over the upcoming cycle would occur on a different area of tubing and not continue in the existing location. The wear in the incore thimble tube was due to vibrational wear. It was noted that all “new” thimble tubes (with the chromium coating) that were replaced during the previous refueling outage showed no indications of wear. Based on the 47% defect, performance of eddy current testing for Unit 2 remains on a schedule of every refueling outage to allow continued frequent monitoring of tube conditions.

9. In April 2019, an effectiveness review was performed on the Augmented Inspection Activities AMA (UFSAR Section 18.2.1) that includes flux thimble tubes among its inspection activities. The AMA was evaluated against the performance criteria identified in NEI 14-12, “Aging Management Program Effectiveness.” No gaps were identified by the effectiveness review related to flux thimble tube inspections.

The above examples of operating experience provide objective evidence that the *Flux Thimble Tube Inspection* program includes activities to perform eddy current testing to identify loss of material for the pressure boundary provided by the flux thimble tubes, and to initiate corrective actions. Occurrences identified under the *Flux Thimble Tube Inspection* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Flux Thimble Tube Inspection* program will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Flux Thimble Tube Inspection* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.25 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

Program Description

The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program is an existing condition monitoring program that manages the following aging effects:

- Cracking or blistering, flow blockage, hardening or loss of strength, and loss of material of polymeric components
- Cracking, flow blockage, loss of material, and reduction of heat transfer of metallic components

This program consists of visual inspections of accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components, and other components exposed to closed-cycle cooling water, raw water, treated water, diesel exhaust, air, condensation, fuel oil, lubricating oil, and waste water. Aging effects associated with items within the scope of the *Open-Cycle Cooling Water System* program (B2.1.11), *Closed Treated Water Systems* program (B2.1.12), and *Fire Water System* program (B2.1.16) are not managed by this program.

Inspections of metallic components monitor for visible evidence of loss of material. Indicators of aging effects for metallic components include corrosion and surface imperfections; loss of wall thickness; flaking or oxide-coated surfaces; debris accumulation on heat exchanger tube surfaces; and accumulation of particulate fouling, biofouling, or macro fouling.

Surface examinations or ASME Code, Section XI, visual examinations (VT-1) are conducted to detect cracking of stainless steel and copper alloy (>15% Zn) components.

Inspections of polymeric and elastomeric components monitor for changes in material properties or loss of material. Indicators of loss of material and changes in material properties include surface cracking, crazing, scuffing, loss of sealing, dimensional change, loss of wall thickness, discoloration, exposure of internal reinforcement, hardening, and blistering. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength is used to augment the visual examinations conducted under this program.

The internal inspections are performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. At a minimum, in each 10-year period during the subsequent period of extended operation, 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 will be inspected.

Where the sample size is not based on the percentage of the population, it is acceptable to reduce the total number of inspections to 19 components per population at each unit. The reduced total number of inspections is acceptable because the operating conditions and history at each unit are sufficiently similar (e.g., flowrate, chemistry, temperature, excursions) such that aging effects are not occurring differently between the units. Past power uprates were implemented for both units at approximately the same time. Historically, water chemistry conditions between the two units have been very similar. The raw water source for both units is the North Anna Reservoir via a common intake structure. Emergency diesel generator testing runs are consistent, so exhaust deposition is equal between engines. Operating experience for each unit demonstrates no significant difference in aging effects of systems in the scope of this program between the two units.

If any inspections do not meet the acceptance criteria, additional inspections will be conducted, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (i.e., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the next refueling outage interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval.

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 even if the minimum number of inspections has been conducted.

Inspections are performed by personnel qualified in accordance with procedures and programs to perform the specified task. Inspections within the scope of the ASME Code follow procedures consistent with the ASME Code. Non-ASME Code inspection procedures include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the subsequent period of extended operation. For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions.

NUREG-2191 Consistency

The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program is an existing program that, following enhancement, will be consistent, with NUREG-2191, Section XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Parameters Monitored/Inspected (Element 3) and Detection of Aging Effects (Element 4)

1. Procedures will be revised to require inspection of elastomeric and flexible polymeric components for the following:
    - Surface crazing, scuffing, loss of sealing, blistering, and dimensional change (e.g., “ballooning” and “necking”)
    - Loss of wall thickness
    - Exposure of internal reinforcement (e.g., reinforcing fibers, mesh, or underlying metal) for reinforced elastomers
2. Procedures will be revised to specify that visual inspection of elastomeric and flexible polymeric components is supplemented by tactile inspection to detect hardening or loss of suppleness. The minimum surface area for tactile inspections will be at least 10% of the accessible surface area.

Detection of Aging Effects (Element 4)

3. Procedures will be revised to specify that follow-up volumetric examinations are performed where irregularities that could be indicative of an unexpected level of degradation are detected for steel components exposed to raw water, raw water (potable), or waste water.

Detection of Aging Effects (Element 4); Monitoring and Trending (Element 5); Acceptance Criteria (Element 6); and Corrective Actions (Element 7)

4. Procedure(s) will be revised or developed to specify the following:
    a. In each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed for the various sample populations (each material, environment, and aging effect combination). If opportunistic inspections will not fulfill the minimum number of inspections by the end of each 10-year period, the program owner will initiate work orders as necessary to request additional inspections. A representative

sample of 20% of the population (defined as components having the same material, environment, and aging effect combination) or a maximum of 19 components per population at each unit will be inspected. The new procedure will specify that the inspections focus on the bounding or lead components most susceptible to aging due to time in service and severity of operating conditions.

b. The rate of degradation will be evaluated and projected until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection sampling bases (e.g., selection, size, frequency) will be adjusted as necessary based on the projection.

c. Additional inspections will be performed if any sampling-based inspections do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination are inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the next refueling outage interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval.

Detection of Aging Effects (Element 4) and Acceptance Criteria (Element 6)

5. The existing inspections of the Unit 1 and Unit 2 bearing cooling system, performed under the Corrective Action Program, will be enhanced to require performance of a minimum of 10 piping wall thickness measurements at each Unit with a frequency not to exceed two refueling cycle intervals. Locations with a wall thickness of less than 50% will be selected and augmented as necessary considering prior inspection results, extent of degradation, rate of degradation, and timing of the next inspection.

Acceptance Criteria (Element 6)

6. Procedure(s) will be revised or developed to specify that, where practical, acceptance criteria are quantitative (e.g., minimum wall thickness). For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative

evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. Since January 2009, several through wall leaks or pitting with depths greater than 50% of wall thickness have been identified in bearing cooling system piping. The degradation was caused by pitting corrosion, and microbiologically influenced corrosion (MIC) and is characterized as recurring internal corrosion (RIC). Through-wall piping leaks are tracked and trended through system health reports. At-risk piping is identified and work orders for replacement are initiated as needed. Areas are identified where chronic through-wall leaks have previously occurred and corrective action initiated to prevent recurrence. NDE UT examinations are performed on piping areas deemed susceptible to determine corrosion rates. Data obtained from UT examinations supplement information obtained through the work control process.

2. In April 2009, after returning a Unit 1 main turbine lube oil cooler to service, a high differential pressure was noted across the cooler on the bearing cooling (tube) side. Following removal from service, the cooler was inspected and a layer of corrosion debris was found on the inlet tube sheet. Inspection of the inlet piping found flaking corrosion products and the inlet elbow had been stripped of its corrosion layer. The debris was determined to be pipe scale/rust from the carbon steel bearing cooling system supply piping. An apparent cause evaluation was conducted that determined the cause of the event to be ineffective dry layup of the standby cooler.

   In 2007, operating procedures had been revised to place the standby lube oil cooler in dry layup and to ensure the bearing cooling supply piping to the cooler is drained. Prior to this, layup of the standby cooler had been wet, or flow throttled on the bearing cooling side. The new dry layup procedure drained bearing cooling water from the cooler and the inlet piping, although system orientation prevented complete draining. The outlet piping was not drained, and therefore, contained stagnant water that contributed to the humid environment within the inlet piping. Based on these findings, the supply and return piping were hydrolased and chemically treated prior to dry layup.

   An evaluation of the effectiveness of the new strategy was conducted in 2011. The examination identified a uniform rust layer on the pipe internal surfaces, along with a small amount of water in the bottom of the pipe. There was no visible degradation noted on pipe internal surfaces as compared to the as-left condition in 2010. Engineering determined that this chemical treatment along with scheduled periodic inspection of the lube oil cooler tube sheet and internal pipe inspections would prevent the re-occurrence of the issue.

3. In September 2011, a through-wall leak was noted on a carbon steel tank that is used to add chemicals to the secondary system.

   The through-wall leak was first noted on the tank in 2008 and a weld overlay was performed to stop the leak. A leak reoccurred at the repair location in May 2011. Another weld overlay was performed that failed later that year.

   The apparent cause was due to the interaction of the chemicals added to the tank was directly contributing to corrosion of the internal surfaces of the carbon steel tank.

   A design change was implemented that replaced the carbon steel tank with a stainless steel tank to mitigate any further corrosion. Since replacement of the tank, no further through-wall conditions have been noted.

4. In January 2015, an action was initiated to monitor bearing cooling pipe wall thicknesses that are most susceptible to corrosion or MIC leaks based on low flow conditions and/or previous through-wall leaks. Periodic inspections were completed using a combination of LFET and ultrasonic thickness measurements.

   As part of the wall thickness monitoring plan, requests were submitted for nondestructive examination (NDE) at locations that were based on accessibility and historical operating experience. In addition to areas inspected in a 2006 and 2007 wall thickness measurement plan, areas which had experienced through-wall leaks because of low flow or stagnant conditions were included in the list of test locations. Data from the 2006 and 2007 inspections served as baseline data to determine degradation rates.

   Testing for both units was conducted in 2016 and documented in engineering technical evaluations. The pipe sections will continue to be trended through engineering technical evaluations approximately every two years to monitor pipe thinning. Bearing cooling piping (20-inch and 24-inch) wall thickness is trended and piping replacements are initiated based on the trend results.

5. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion reached was that performance deficiencies or learning opportunities were identified for the Work Control Process AMA (UFSAR Section 18.2.19). The assessment identified that some systems in the scope of license renewal that credit the Work Control Process AMA (UFSAR Section 18.2.19) to manage aging were not identified as such in the plant database. Consequently, as-found

inspection forms were not automatically generated when work orders were initiated for these systems. An update was made to the database to correct the designation.

6. In October 2016, a condition report documented five MIC leaks on a Unit 1 segment of stainless steel bearing cooling piping that contained raw water.

   A work order replaced the affected sections of piping. The as-found inspection form noted that the existing upstream and downstream piping was in good condition.

   In an evaluation of the condition, Engineering noted that MIC leaks on the bearing cooling makeup piping have occurred in the past and have typically been very small pinholes. Engineering recommended no further corrective actions following replacement of the affected piping.

7. In November 2016, a condition report documented a through-wall leak on Unit 2 bearing cooling system carbon steel piping containing raw water. A soft patch was installed on the leak location.

   A corrective action assignment was made to Engineering to evaluate the condition. Engineering identified the likely cause as MIC. As a proactive measure to monitor for degradation, Engineering performed periodic pipe wall thickness measurements on bearing cooling system piping. As noted above, ultrasonic thickness exams had been previously performed on Unit 1 and 2 bearing cooling system piping. Results of the UT examinations were reviewed and evaluated to determine if any proactive piping replacements were warranted.

   Engineering concluded that the ongoing activities to manage aging in the bearing cooling system preserve long-term system health and reliability.

8. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

9. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion

reached was that an area for improvement or enhancement was identified for the Work Control Process AMA (UFSAR Section 18.2.19). Areas for improvement included administrative updates to aging management program implementing procedures to ensure they are identified as such, and steps to implement on-going commitments are identified.

10. In September 2017, a condition report was initiated to document the build-up of sediment in a Unit 2 turbine lube oil cooler during a borescope inspection of the cooler inlet and outlet piping.

    Engineering noted that the condition did not challenge the ability of the turbine lube oil cooler to perform its design function, but recommended cleaning the piping prior to returning the cooler to service. A work order was performed to vacuum the debris in the lines.

    Additionally, Engineering performed an evaluation of the current strategy for maintenance of the lube oil coolers with consideration given to the sediment issue. Engineering reviewed five years of clean/inspect and maintenance records on each of the coolers. Throughout the reviewed maintenance history, there were no reports or indications of any significant blockages or organic growths or buildups prior to cleaning that would have challenged the intended function of the heat exchanger.

    Engineering determined that the existing strategy to clean and inspect each heat exchanger after every 18-month service cycle was conservative and sufficient to maintain the lube oil cooler intended function.

11. In April 2019, an effectiveness review was performed on the Work Control Process (UFSAR Section 18.2.19). The AMA was evaluated against the performance criteria identified in NEI 14-12, "Aging Management Program Effectiveness." Gaps were identified by the effectiveness review related to Work Control Process AMA (UFSAR Section 18.2.19) related components or activities.

    A significant element of the Work Control Process AMA consists of opportunistic visual inspections conducted on the internal surfaces of plant components and adjacent piping that are in the scope of license renewal to monitor for aging effects such as cracking and loss of material. These opportunistic inspections are performed on in-scope components during maintenance activities. Potential age-related degradation conditions are recorded on "as-found" inspection forms within the work orders and dispositioned as necessary in the Corrective Action Program. The Work Control Process AMA is implemented by plant procedures.

    The effectiveness review identified an area for improvement associated with the license renewal as-found inspection forms. The review indicates that overall the inspections were performed when required; however, needed administrative improvements were identified. A condition report was submitted to address the concerns.

Recurring Internal Corrosion (RIC)

Recurring internal corrosion, including through-wall failures as a result of loss of material due to pitting and MIC, has been observed in bearing cooling system piping. From 2005 to 2016, several Unit 1 and Unit 2 bearing cooling system lines ranging in size from 2 inches through 12 inches have been replaced. Bearing cooling system piping wall thickness measurements were performed and evaluated to identify when corrective actions or pipe replacement were required prior to a loss of intended function. An Engineering evaluation of 52 Unit 1 locations examined in 2016 indicated that four runs of pipe (12 inches and 24 inches) exceeded acceptable corrosion rates. Of these, two were scheduled for replacement within 10 years and the remaining two did not require replacement for more than 20 years. An Engineering evaluation of 48 Unit 2 locations examined in 2016 indicated that three runs of pipe (12 inches and 16 inches) exceeded acceptable corrosion rates. However, none of the Unit 2 piping required replacement within the next 30 years. Piping wall thickness measurements for vulnerable bearing cooling water system piping are collected at two refueling cycle intervals.

The existing bearing cooling system wall thickness examinations will be enhanced to perform a minimum of 10 piping wall thickness measurements at each Unit with a frequency not to exceed two refueling cycle intervals. Locations in the 2016 sample population with a wall thickness of less than 50% will be selected and augmented as necessary considering prior inspection results, extent of degradation, rate of degradation, and timing of the next inspection.

The above examples of operating experience provide objective evidence that the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program includes activities to perform opportunistic inspections to identify cracking, flow blockage, loss of material, and reduction of heat transfer of metallic components. The program also includes activities to perform opportunistic inspections to identify hardening or loss of strength, loss of material, cracking or blistering, and flow blockage of polymeric components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.26 Lubricating Oil Analysis

Program Description

The *Lubricating Oil Analysis* program is an existing preventive program that ensures loss of material and reduction of heat transfer is not occurring by maintaining the quality of the lubricating oil or hydraulic oil. The program ensures that contaminants (primarily water and particulates) are within acceptable limits and are consistent with vendor and industry guidelines.

The program directs condition monitoring activities (sampling, analyses, and trending), thereby preserving an environment that is not conducive to loss of material or reduction of heat transfer. The lubricating oil testing (sampling and analysis) and condition monitoring activities identify detrimental contaminants such as water, sediments, specific wear elements, and elements from an outside source. The contaminant levels (e.g., water and particulates) are trended in the program's database, and corrective actions are initiated when the presence of water or particulate is identified which could include evaluating for in-leakage and corrosion product buildup.

The *Lubricating Oil Analysis* program applies monitoring methods that are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent significant degradation.

To verify the effectiveness of the *Lubricating Oil Analysis* program, selected components will be inspected as described in the *One-Time Inspection* program (B2.1.20), to ensure that degradation is not occurring and the component's intended functions are maintained during the subsequent period of extended operation.

NUREG-2191 Consistency

The *Lubricating Oil Analysis* program is an existing program that is consistent with NUREG-2191, Section XI.M39, Lubricating Oil Analysis.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Lubricating Oil Analysis* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In January 2008, approximately five gallons of water was drained from the Unit 2 main lube oil reservoir, but no sediment was identified. As a result, subsequent trending and monitoring identified that the source of the water ingress was at the Unit 2 #6 steam gland. Repairs were completed during the September 2008 refueling outage with no further instances of water in the oil.
2. In July 2014, a Unit 2 electro-hydraulic control (EHC) fluid test sample indicated elevated particle count at 16 particles above 100 microns in size. The results exceeded the acceptance criteria of five particles above 100 microns. Engineering reviewed previous samples taken and concluded the most recent sample was likely suspect based on no recent history of high particle counts. Another sample was subsequently taken, which resulted in only one particle above 100 microns in size. Engineering reviewed Unit 2 EHC parameters in the Turbine Building operations logs and conditions were concluded to be normal. After evaluating the data and the subsequent sample results, Engineering determined the Unit 2 EHC system was functioning as required.
3. In March 2015, the Unit 1 auxiliary feedwater turbine outboard bearing housing sight glass was reported to be cloudy and layered indicating a potential issue with water intrusion into the oil system. Oil testing confirmed the presence of water. The oil was removed and tested with an observed water concentration of 0.1%, by an off-site laboratory facility.

   Engineering concluded that maintaining the amount of water in the oil to less than 0.5% would not impact the reliable operation of the pump or turbine. The apparent cause of the water intrusion was determined to be associated with how the insulation was affixed to the outboard end of the turbine. Steam leakage from the turbine gland was prevented from dissipating to the atmosphere causing the trapped steam to condense and be directed towards the outboard turbine bearing. The turbine insulation was subsequently removed from the turbine casing to allow for a better visual inspection of the gland and the cutout for the shaft was enlarged to help prevent steam being trapped and condensing onto the bearing housing. Oil samples taken in 2018 were negative for water intrusion.
4. In April 2019, an effectiveness review was performed on the Work Control Process AMA (UFSAR Section 18.2.19) that includes Lubricating Oil Analysis among its inspection activities. The AMA was evaluated against the performance criteria identified in NEI 14-12, “Aging Management program Effectiveness.” No gaps were identified by the effectiveness review related to Lubricating Oil Analysis.

The above examples of operating experience provides objective evidence that the *Lubricating Oil Analysis* program includes activities to perform lubricating oil and EHC fluid analysis to identify any degradation in the quality of the lubricating oil or hydraulic oil that could cause loss of material or reduction of heat transfer for components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Lubricating Oil Analysis* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Lubricating Oil Analysis* program will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Lubricating Oil Analysis* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.27 Buried and Underground Piping and Tanks

Program Description

The *Buried and Underground Piping and Tanks* program is an existing condition monitoring program that manages blistering, cracking, hardening or loss of strength, and loss of material on external surfaces of piping and tanks in soil, concrete, or underground environments within the scope of subsequent license renewal through preventive and mitigative actions. The program addresses stainless steel, carbon steel, cast iron, ductile iron, copper alloy, and fiberglass piping and tanks.

Depending on the material, preventive and mitigative techniques include external coatings, cathodic protection (CP), and the quality of backfill. Direct visual inspection quantities for buried components are planned using procedural categorization criteria. Transitioning to a higher number of inspections than originally planned is based on the effectiveness of the preventive and mitigative actions. Also, depending on the material, inspection activities include annual surveys of CP, non-destructive evaluation of pipe or tank wall thicknesses, and visual inspections of the pipe from the exterior.

The buried carbon steel piping of the service water system and the flood protection dike drain is protected by an active CP system. Periodic inspections confirm CP system availability and reliability. Annual CP surveys are conducted to assess the effectiveness of the CP system. The program uses the -850 mV relative to CSE (copper/copper sulfate reference electrode), instant off criterion specified in NACE SP0169 for acceptance criteria for steel piping and tanks and determination of cathodic protection system effectiveness in performing cathodic protection surveys. The program includes an upper limit of -1200 mV on cathodic protection pipe-to-soil potential measurements of coated pipes to preclude potential damage to coatings. For steel components, where the acceptance criteria for the effectiveness of the cathodic protection is other than -850 mV instant off, loss of material rates are measured. The buried carbon steel piping of the fuel oil system for the emergency electrical power system will be refurbished and reconnected to the service water CP system described above.

Soil sampling and testing is performed during each excavation and a station-wide soil survey based on initial baseline data is also performed once in each 10-year period to confirm the soil corrosivity level near components within the scope of license renewal for the installed material types. Soil sampling and testing is consistent with EPRI Report 3002005294, “Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants.” Soil survey baselines were performed in 2011.

External inspections of buried components within the scope of subsequent license renewal will occur opportunistically when they are excavated for any reason.

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 subsequent period of extended operation an increase in the sample size is conducted.

As an alternative to performing visual inspections of the buried fire protection system components, monitoring the activity of the jockey pump is performed by the *Fire Water System* program (B2.1.16). The water-based fire protection system is normally maintained at required operating pressure and is monitored such that a loss of system pressure is detected and corrective action initiated.

The *Selective Leaching* program (B2.1.21) is applied in addition to this program to manage selective leaching for applicable materials in soil environments.

The *Buried and Underground Piping and Tanks* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *Buried and Underground Piping and Tanks* program is an existing program that, following enhancement, will be consistent, with NUREG-2191, Section XI.M41, Buried and Underground Piping and Tanks.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program element(s):

Preventive Actions (Element 2)

1. Procedures will be revised to obtain pipe-to-soil potential measurements for piping in the scope of SLR during the next soil survey within 10 years prior to entering the subsequent period of operation.

Detection of Aging Effects (Element 4) and Corrective Actions (Element 7)

2. The following service water CP subsystems will be refurbished and reconnected before the last five years of the inspection period prior to entering the subsequent period of extended operation.
   a. The service water ‘D’ CP subsystem
   b. The service water ‘C’ CP subsystem associated with the buried carbon steel piping of the fuel oil system for the emergency electrical power system

Acceptance Criteria (Element 6)

3. Procedures will be revised to specify that cathodic protection surveys use the -850 mV polarized potential, instant off criterion specified in NACE SP0169-2007 for steel piping acceptance criteria unless a suitable alternative polarization criteria can be demonstrated. Alternatives will include the -100 mV polarization criteria, -750 mV criterion (soil resistivity is greater than 10,000 ohm-cm to less than 100,000 ohm-cm), -650 mV criterion (soil resistivity is greater than 100,000 ohm-cm), or verification of less than 1 mpy loss of material rate.
   a. The external loss of material rate is verified:
      - Every year when verifying the effectiveness of the cathodic protection system by measuring the loss of material rate.
      - Every 2 years when using the 100 mV minimum polarization.
      - Every 5 years when using the -750 or -650 mV criteria associated with higher resistivity soils. The soil resistivity is verified every 5 years.
   b. As an alternative to verifying the effectiveness of the cathodic protection system every five years, soil resistivity testing is conducted annually during a period of time when the soil resistivity would be expected to be at its lowest value (e.g., maximum rainfall periods). Upon completion of ten annual consecutive soil samples, soil resistivity testing can be extended to every five years if the results of the soil sample tests consistently have verified that the resistivity did not fall outside of the range being credited (e.g., for the -750 mV relative to a CSE, instant off criterion, measured soil resistivity values were greater than 10,000 ohm-cm).
   c. When using the electrical resistance corrosion rate probes:
      - The individual determining the installation of the probes and method of use will be qualified to NACE CP4, “Cathodic Protection Specialist” or similar
      - The impact of significant site features and local soil conditions will be factored into placement of the probes and use of the data

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Buried and Underground Piping and Tanks* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In November 2005, a through-wall leak was discovered in a weld in Unit 1 underground stainless steel safety injection system piping. A portion of the piping was replaced and weld repair was also performed. The Root Cause Evaluation determined the cause to be stress corrosion cracking due to inadequate original construction welding procedures that did not specify the maximum heat input. The high heat input applied during welding to this type of material resulted in sensitizing the weld. The adverse environmental condition attributed to the inside diameter cracking was possible high chloride content in the fluid. Groundwater dripping on the piping was the source for the adverse environmental condition for the outside diameter cracking.
2. In May 2010, stainless steel chemical and volume control, quench spray, residual heat removal, and safety injection buried piping associated with the Unit 1 refueling water storage tank was excavated and inspected. A portion of the external coating was degraded and brittle. No adverse condition or corrosion was found and the coating was restored and the pipes were reburied.
3. In June 2010, stainless steel and carbon steel piping associated with the Unit 1 chemical addition tank was excavated and inspected. The stainless steel piping had no indications of pitting or corrosion. The carbon steel piping had degraded coating with general surface corrosion.
4. In January 2012, stainless steel quench spray piping associated with the Unit 1 refueling water storage tank was excavated and inspected. Both pipes had disbonded coating, but there were no signs of corrosion or degradation. Ultrasonic test results were reviewed by Engineering and found to be acceptable minimum wall thickness. The disbonded coating was repaired.
5. In September 2012, opportunistic inspection of stainless steel Unit 2 Casing Cooling Pump House floor drain piping was excavated and inspected. Coating was found to be disbonded and removed after excavation. There were no indications of pitting or corrosion. Ultrasonic testing indicated greater than minimum wall thickness.The disbonded coating was repaired.
6. In May 2013, following replacement of cast iron with (and installation of new) ductile iron fire main piping, the scope of cast iron fire protection piping replacement with ductile iron was reduced to the portion identified as high priority due to the postulated pipe rupture in this area potentially challenging adjacent safety-related piping. The buried fire protection piping on the west side of the station that serves as the backup water supply to the Unit 2 auxiliary

feedwater system was replaced. Also, the buried cast iron fire protection piping at the northwest and southwest tie-in connection points was replaced with ductile iron pipe. New ductile iron pipe was installed at the Southeast Security Building. The basis for scope reduction also included the good condition of existing fire piping found in at least five buried fire main locations. The internal cementitious lining was determined to be in good condition, fully intact, and protecting the pipe in these cases.

7. In November 2014, evaluation was completed of a baseline soil survey conducted during 2011 that involved 25 samples (24 sample locations are within the scope of subsequent license renewal). Soil samples were extracted from various plant locations where safety related piping or piping that contained nuclear/environmentally hazardous material was buried. Ratings for soil resistivity, water content, pH, sulfide content, groundwater level, redox potential, and chloride concentration parameters were compiled to determine a corrosivity index. Using a corrosivity index consistent with American Water Works Association C105, “Polyethylene Encasement for Ductile-Iron Pipe Systems,” the 24 samples within the scope of subsequent license renewal were determined to be non-corrosive.

8. In July 2015, service water CP system test results indicate that the majority of the piping associated with CP subsystems ‘A,’ ‘B,’ and ‘C’ are receiving adequate cathodic protection as defined in NACE SP 0169-2013 for both the -0.850 volt and 100-millivolt criteria. Test results indicate a lack of protection on the extreme ends of the system where the pipes enter the concrete vaults or buildings. The ‘D’ subsystem was shut off because test results indicated that the service water piping was not receiving a level of protection consistent with the ‘D’ subsystem’s rectifier output. The service water piping protected by the ‘D’ subsystem was volumetrically inspected. There are no issues with the service water piping and no issues will be induced from shutting off the ‘D’ subsystem; the service water piping remains fully capable of performing its intended functions. CP ‘D’ subsystem will be refurbished and reconnected before the last five years of the inspection period prior to entering the subsequent period of extended operation.

9. In August 2015, during an Underground Piping and Tanks program inspection of cast iron fire protection and carbon steel bearing cooling piping associated with the bearing cooling tower found the pipe to be in good condition. In particular, the bearing cooling piping excavated did not show evidence of material degradation, pitting, gross corrosion, or other abnormalities. New coatings were applied to the bearing cooling piping prior to backfill.

10. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion reached was that performance deficiencies or learning opportunities were identified for the Buried Piping and Valve Inspection AMA (UFSAR Section 18.1.1). From a review of inspection documentation,

no discussion of tape wrap removal to inspect epoxy coating was discovered. A follow-on action was initiated ensure evaluation of this omission as part of summarizing buried piping activities for license renewal. The required inspections of in-scope stainless steel piping were conducted. In cases where stainless steel piping was found without coating or with significantly disbonded coating, no evidence of pitting or corrosion existed. It was concluded that there is no benefit to the removal of any tape wrap to inspect the coating underneath.

11. In September 2016, unsatisfactory output voltage and current were measured while performing bimonthly inspection of service water CP subsystem ‘C.’ Although the output voltage and the output current have not been within the procedural band (−850 mV relative to a CSE, instant off, and 100 mV minimum polarization), the “On” potentials and the “Instant Off” potentials have been consistent and within the acceptable band since May 2013. Engineering will continue to monitor this CP Subsystem on the bimonthly schedule.

12. In October 2016, leakage was observed outside the Unit 1 Auxiliary Feedwater Pump House. A leak of 1-2 gallons per minute was observed from the joint between the concrete walkway and the foundation. After excavation, the leak location was identified in an elbow of a direct buried service water pipe. The failure mechanism was determined to be external corrosion caused by the lack of an external protective coating. The service water elbow was replaced and protective coating was applied to the external surfaces. The accessible adjacent service water piping was also tape-wrapped. The service water line was returned to service.

13. In December 2016, suspected leakage in buried carbon steel piping from the Fuel Oil Pump House to the ‘2H’ diesel room was identified. The leakage was due to localized corrosion on the outside diameter of the pipe due to coating / tape wrap degradation (direct cause). The failure of the coating permitted localized corrosion on the pipe due to chemical attack from the buildup of contaminants on the surface of the pipe.

    The extent of condition included pressurized fuel oil supply lines buried between the Fuel Oil Pump House and each EDG room, along with the SBO EDG room. The buried fuel oil lines in that scope have been replaced with stainless steel and placed in service.

14. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.

15. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the Buried Piping and Valve Inspection Activities AMA (UFSAR Section 18.1.1).
16. In April 2019, an effectiveness review was performed on the Buried Piping and Valve Inspection Activities AMA (UFSAR Section 18.1.1) The AMA was evaluated against the performance criteria identified in NEI 14-12, "Aging Management Program Effectiveness." No gaps were identified by the effectiveness review.

The above examples of operating experience provide objective evidence that the *Buried and Underground Piping and Tanks* program includes activities to perform volumetric and visual inspections to identify blistering, cracking, hardening or loss of strength, and loss of material for buried and underground piping and tanks within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Buried and Underground Piping and Tanks* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Buried and Underground Piping and Tanks* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Buried and Underground Piping and Tanks* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.28 Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

Program Description

The *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program is an existing condition monitoring program that manages loss of coating integrity of the in-scope components exposed to closed-cycle cooling water, raw water, treated water, treated borated water, waste water, lubricating oil, fuel oil, and air-dry environments, that can lead to loss of base materials or downstream effects such as reduction in flow, reduction in pressure or reduction of heat transfer when coatings/linings degrade and become debris. The program manages loss of material or cracking for cementitious coatings/linings.

Periodic visual inspections are conducted for each coating/lining material and environment combinations of the internal surfaces of in-scope piping and components where loss of coating or lining integrity could impact the components or downstream component's intended function(s). Inspection intervals will not exceed those specified in NUREG-2191 Table XI.M42-1, Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers.

For tanks, heat exchangers and piping, all accessible surfaces are inspected. If a baseline inspection has not been previously established, baseline coating/lining inspections will occur in the 10-year period prior to the subsequent period of extended operation. Subsequent inspection intervals are established by a coating specialist qualified in accordance with ASTM International Standards endorsed in RG 1.54, Revision 3, “Service Level I, II and III Protective Coatings Applied to Nuclear Power Plants,” including guidance from the staff associated with a particular standard. For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces. Peeling and delamination are not acceptable. Blisters are evaluated by a coatings specialist. Blisters are limited to a few intact small blisters that are completely surrounded by sound material and with the size and frequency not increasing between inspections. Minor cracks in cementitious coatings are acceptable provided there is no evidence of debonding. Other degraded conditions are evaluated by a coatings specialist. For coated/lined surfaces determined not to meet the acceptance criteria, the coating can be removed, or physical testing is performed, where physically possible (i.e., sufficient room to conduct testing), in conjunction with repair or replacement of the coating/lining.

Opportunistic inspections, in lieu of periodic inspections, are performed as an acceptable alternative for buried internally coated/lined fire water system piping by the *Fire Water System* program (B2.1.16) meeting the following conditions: (a) fire water system piping flow testing is performed consistent with Section 7.3.1 of NFPA 25, 2011 edition, “Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems,” to determine the internal condition of the piping; (b) the water-based fire protection system is maintained at required operating pressure and is monitored such that loss of system pressure is detected and corrective actions initiated; and (c) a review of plant operating experience has not identified any documented leaks due to the age-related degradation of the internal coatings used in buried fire water system piping within the scope of subsequent license renewal.

The *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks as modified by SLR-ISG-Mechanical-2020-XX, Updated Aging Management Criteria for Mechanical Portions of the Subsequent License Renewal Guidance.

Exception Summary

The following program element is affected:

Detection of Aging Effects (Element 4) and Corrective Actions (Element 7)

1. Every four or six years, NUREG-2191 recommends either an inspection of a representative sample of 73 one-foot axial length circumferential segments of piping or 50% of the total length of each coating/lining material and environment combination inspected, whichever is less at each unit. For two-unit sites, 55 one-foot axial length sections of piping (nineteen if manufacturer recommendations and industry consensus documents were complied with during installation) are inspected per unit. An exception is taken to sample size, inspection, and re-inspection frequency. This exception would apply to service water system and circulating water system piping coatings.

Justification for Exception

For each unit, existing piping inspections are performed on approximately 10% of the service water system (24 inch and 36 inch piping) internal coatings during each refueling cycle, thereby inspecting 100% of the service water system piping every 10 refueling cycles (15 years).

The inspection frequency was established based on operating experience with service water system coatings. There have been no Unit 2 piping minimum wall thickness failures as a result of pitting due to loss of coating integrity of in-scope coated service water piping during the last five years (2015-2019). There have only been two Unit 1 piping minimum wall thickness failures on the same header as a result of pitting due to loss of coating integrity of in-scope coated service water piing during the last five years (2015-2019).

Current inspection of approximately 10% of the service water system internal coatings each refueling cycle provides an adequate sample size and are frequent enough to allow early detection of degradation of coatings and the underlying metal before there is a loss of intended function of the piping pressure boundary.

The condition of the internal coatings of the service water system will be assessed during scheduled inspections. Coatings that do not meet acceptance criteria, will be replaced, repaired, or removed. Physical testing is performed where physically possible (i.e., sufficient room to conduct testing) or examination is conducted to ensure that the extent of repaired or replaced coatings/linings encompasses sound coating/lining material. Metallic surfaces exposed as a result of corrective actions will be evaluated. Unexpected degradation (e.g., pitting or erosion) of metallic surfaces will be examined to determine if the minimum wall thickness is met and will continue to be met until the next scheduled inspection.

There has also been no loss of intended function due to flow blockage of the 24-inch and 36-inch service water piping headers and associated heat exchangers supplied by service water.

After performance of a baseline inspection the same sample size, inspection, and re-inspection frequency would apply to the circulating water system pipe coatings

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Scope of the Program (Element 1) and Detection of Aging Effects (Element 4)

1. Procedures will be revised to require baseline inspections (100% of accessible coatings/linings) of the following tanks, piping, and miscellaneous components within the scope of subsequent license renewal and inspection intervals will not exceed those specified in NUREG-2191 Table XI.M42-1, Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers:
    - Condensate polishing Powdex tanks
    - Pressurizer relief tanks
    - Chilled water mechanical chiller cooler (channel head)
    - Circulating water inlet and outlet waterbox piping

- Chemical and volume control flow transmitters (emergency borate header flow and boric acid to blend system flow)
- Fire protection isolation valve
- Drains - bldg. services piping

Corrective Action (Element 7)

2. Procedures will be revised to include as an alternative to repair, rework, or removal, internal coatings/linings exhibiting indications of peeling and delamination. The component may be returned to service if:
    a. Physical testing is conducted to ensure that the remaining coating is tightly bonded to the base metal,
    b. the potential for further degradation of the coating is minimized, (i.e., any loose coating is removed, the edge of the remaining coating is feathered),
    c. adhesion testing using ASTM International Standards endorsed in RG 1.54 (e.g., pull-off testing, knife adhesion testing) is conducted at a minimum of three sample points adjacent to the defective area,
    d. an evaluation is conducted of the potential impact on the system, including degraded performance of downstream components due to flow blockage and loss of material or cracking of the coated component, and
    e. follow-up visual inspections of the degraded coating are conducted within two years from detection of the degraded condition, with a re-inspection within an additional two years, or until the degraded coating is repaired or replaced.
3. Procedures will be revised to require additional inspections 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 of components constructed of the same material and exposed to the same environment. The number of increased inspections will be determined in accordance with the Corrective Action Program. However, there are no fewer than five additional inspections or each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. When inspections are based on the percentage of piping length, an additional 5% of the total length will be inspected. The timing of the additional inspections will be based on the severity of the degradation identified and will be commensurate with the potential for loss of intended function. However, in all cases, the additional inspections will be 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 refueling outage interval. These additional inspections

conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval. 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 will include inspections with the same material, environment, and aging effect combination at Unit 1 and Unit 2.

4. Procedures will be revised to require inspection frequencies for internal coatings/linings of in-scope piping and piping components are performed on a frequency consistent with Table XI.M42-1, various frequencies from 4-12 years.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In October 2001, during the performance testing of the motor-driven, and diesel-driven fire protection pumps a rupture occurred in the twelve-inch main. The line was excavated and the pipe was cut to remove one side of the fracture, which was then submitted for metallurgical analysis. The fracture occurred on the underside or bottom portion of the pipe. Inspection of the outer diameter of the pipe revealed no obvious signs of impact damage or significant corrosion attack. The small pockets of corrosion noted on the outer diameter of the pipe were easily removed. The inner diameter of the pipe also appeared in good condition. Except for the fracture zone, the mortar lining was intact, showing only a fine, craze surface cracking in some areas. There was some minor buildup of sediment noted along the bottom of the pipe. The analysis performed on the pipe failure of the twelve-inch fire protection main determined that the failure most likely occurred as a result of a low cycle fatigue process that originated at a pre-existing manufacturing flaw in the pipe. From a condition assessment standpoint, the overall state of the pipe, from the inner diameter mortar lining to the exterior surface, was in good condition.

2. In August 2009, coating defects with corrosion were discovered on the Unit 1 component cooling heat exchanger '1A' channel head interior. The defects occurred in two locations. One location, on the supply side, had corrosion scattered over a triangular area. The other location, on the return side, contained a patch of corrosion over a small, defunct drain (blocked by a blind flange). The supply-side triangular area contained a mild, intermittent corrosion buildup with no delaminating coating edges. It was determined by Engineering and the coatings specialist that the shell, shell channel head, and drain would not approach min-wall thickness

between the time of discovery and the next Unit 1 component cooling heat exchanger '1A' outage. Inspection results indicated that it was acceptable to defer maintenance until the next Unit 1 component cooling heat exchanger '1A' outage. Coating repairs were performed in August 2012.

3. In April 2010, it was determined that the service water 'A' return header required coating repair. One eight-inch flange in the Quench Spray Pump House required a coating repair around the circumference. Several small areas in the return header also had delaminating topcoat and needed to be sanded down to an adherent edge. The supply header was satisfactory, with several small indications that did not require coating repair. Coating repairs were completed in April 2010.

4. In September 2011, during an Engineering inspection of the Unit 2 discharge tunnel, several coating defects were observed on the interior of the 96-inch 'B' circulating water discharge header. The coating defects were observed to have rust bloom. A sample was excavated, showing that the coating defects go down to bare metal. Additional inspections were performed by Engineering to investigate the extent of condition of exposed bare metal. Inspections of the coating defects did not indicate that the circulating water piping could not perform its design functions. Coating repairs were performed during the Unit 2 Fall 2011 refueling outage.

5. In July 2015, Engineering performed a coatings inspection of the Unit 1 '1B' component cooling heat exchanger and the associated supply/return service water piping to various motor operated valves. Several minor coating defect areas were identified. The internal coating in the heat exchanger was in good condition with minor coating damage occurring on the flow diverter plate edges, on the shell wall behind the diverter plates, and sporadically along the flange seating area. Since the exposed metal in these locations showed only minor corrosion, Engineering determined it was acceptable to perform the coating repairs during the next scheduled preventive maintenance work order. As part of the repair process, the flow diverter plates were unbolted and sent to the paint shop for proper surface preparation. The shell and flange coating repair areas were performed in the field. Repair of the internal coating was completed in July 2017.

6. In March 2016, the Unit 2 emergency condensate storage tank was inspected during the Spring 2016 refueling outage. The inspection consisted of performing a visual inspection of the interior coating and spot ultrasonic testing (UT) examinations on the tank bottom, wall, and roof from inside the tank. The interior coatings inspection found the existing coating to be in excellent condition with minor coating defects occurring at the top of the tank above the normal fill line, the tank dome, and two spots on the tank wall. The wall defects were two small pin holes through the top coat with a completely adhered and intact primer coat. The top of the tank wall and dome had minor surface cracking in some areas with minor surface staining. The

coatings were tightly adhered. Thickness measurements were performed on the tank bottom, the tank wall/shell, and on a quarter section of the roof at the roof/wall joint. Data obtained from the tank bottom was satisfactory. Data obtained from the tank roof and walls showed no significant wall thinning but did reveal some potentially localized pitting (from the inaccessible exterior). Thickness measurements at three locations on the wall were found to be below the specified minimum thickness. Engineering reviewed the wall thickness in these few localized areas and found them acceptable. A work order has been initiated to obtain wall thickness data on the tank shell during the next scheduled coatings inspection at locations where minimum thickness was observed. The results will be used to determine a corrosion rate and initiate any additional corrective action if required.

7. In September 2017, initial inspection of the ‘D’ inlet and outlet waterboxes was completed satisfactorily. However, minor coating repairs were recommended in both the inlet and outlet 'D' waterboxes. Coating was starting to chip in a couple small spaces on the tube sheet of the 'D' outlet and the seams around the tube sheet were chipped all the way around on the 'D' outlet. The seam on the 'D' inlet needed repair for minor chipping as well. Coating repairs were completed in September 2017.
8. In July 2018, during inspection of service water piping between the v-cone and tie-in vault manway, three additional coating repairs were identified in service water segment 12. Coating blisters and defects in the line were not repaired during the Spring 2014 'B' service water header outage. Not repairing the coating defects, in the piping between the service water pump house and tie-in vault, allowed portions of the carbon steel material to be exposed to the service water medium. Engineering determined that, in the areas where pitting of the carbon steel piping material has occurred, weld repair is not required. Coating repairs were completed in July 2018.

Recurring Internal Corrosion (RIC)

From 2014 to 2019 recurring internal corrosion (RIC) due to loss of coating integrity has occurred in the coated service water (SW) system piping and component cooling heat exchanger channel head. During the 2014 to 2019 period, the following operating experience for coated service water pipe within the scope of license renewal resulted in pitting of the pipe below the minimum wall thickness:

- In 2014 a loss of coating integrity was identified in the Unit 1 SW ‘A’ header (36-inch) located between the yard manway and the service water tie-in vault
- In 2015 a loss of coating integrity was identified in the Unit 1 SW ‘B’ header (36-inch) in the service water pumphouse
- In 2017 a loss of coating integrity was identified in the Unit 1 SW ‘B’ header (36-inch) in the service water pumphouse

During the last five years (2015-2019), there has been no Unit 2 piping minimum wall thickness failures as a result of pitting due to loss of coating integrity of in-scope coated service water piping. During the last five years (2015-2019), there have only been two Unit 1 piping minimum wall thickness failures on the same header as a result of pitting due to loss of coating integrity of in-scope coated service water piping.

The *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program monitors the condition of the internally coated piping to minimize the likelihood of piping and component degradation as a result of loss of material due to pitting and microbiologically influenced corrosion. For piping sections inspection of approximately 10% of the service water system internal coatings each refueling cycle provides an adequate sample size for detecting aging effects prior to loss of intended function. As a result of the inspection protocol with a 10% sample population, 100% of the service water internal coatings is inspected every 15 years.

Plant operating experience has demonstrated that component cooling heat exchanger channel heads inspections performed on a three-year frequency which allows early detection of degradation of coatings and the underlying metal before there is a loss of intended function.

Visual inspections are intended to identify coatings that do not meet acceptance criteria, such as peeling and delamination. Pipe wall thickness measurements may be performed to determine if pitting has resulted in a wall thickness that does not meet the design minimum wall thickness and the need to perform a repair or replacement activity.

The condition of the internal coatings and underlying metal of the service water system will be assessed during scheduled inspections, and any degraded conditions not meeting acceptance criteria will be recorded in the Corrective Action Program. The need for increased inspections will be evaluated as part of the corrective actions, considering past inspection results, extent of degradation, rate of degradation, and the timing of the next inspection.

The above examples of operating experience provide objective evidence that the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program includes activities to perform visual inspections of internal surfaces to identify loss of coating integrity for piping, piping components, heat exchangers and tanks within the scope of subsequent license renewal, and to initiate corrective actions. The program also manages loss of material or cracking for cementitious coatings/linings. Occurrences identified under the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.29 ASME Section XI, Subsection IWE

Program Description

The *ASME Section XI, Subsection IWE* program is an existing condition monitoring program that manages cracking, loss of material, loss of sealing, loss of preload, and loss of leak tightness by providing aging management of the steel liner of the concrete Containment. ASME Section XI, Subsection IWE program inspections are performed in order to identify and manage containment liner aging effects that could result in loss of intended function for the subsequent period of extended operation. Included in this inspection program are the containment liner plate and its integral attachments, containment penetrations, containment hatches, airlocks, and pressure retaining bolting.

Surface and volumetric examinations are performed to identify indications of degradation. The primary inspection method is visual examination (general visual, VT-1, VT-3) of surfaces for evidence of cracking, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents, and other signs of surface irregularities, including discernible liner plate bulges. Limited volumetric examinations (ultrasonic thickness measurement) and surface examinations (e.g., liquid penetrant) are performed, as required. Plant operating experience has not identified any discernible bulges requiring further examination. Acceptance criteria, corrective actions, and expansion of the inspection scope when degradation exceeding the acceptance criteria is found are in accordance with ASME Code, Section XI, Subsection IWE, Article IWE 3000.

For the third containment inspection interval, beginning during the third quarter of 2017, IWE containment inservice inspections are performed in accordance with ASME Code, Section XI, Subsection IWE, 2007 Edition (through the 2008 addenda). In conformance with 10 CFR 50.55a(g)(4)(ii), the ASME Section XI, Subsection IWE program will be updated during each successive 120-month inspection interval to comply with the requirements of the latest edition and addenda of the ASME Code specified 12 months before the start of the inspection interval.

Using the guidance in NRC Information Notice 2014-07 (IN 2014-07), the containment basemat liner leak chase channel test connections are regarded as “Moisture Barriers”, and the accessible areas are subject to general visual examinations in accordance with ASME Code, Section XI, Subsection IWE, Table IWE 2500-1, Examination Category E-A, Item E1.30.

Procedures and specifications include preventive actions to ensure bolting integrity for replacement and maintenance activities by specifying proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload. There are no ASTM A325 and/or ASTM A490 bolts (including respective equivalent twist-off type ASTM F1852 and/or ASTM F2280 bolts) within the scope of the *ASME Section XI, Subsection IWE* program.

There are no stainless steel penetration bellows installed as part of the containment pressure boundary. Stainless steel high energy pipes that penetrate the Containment are connected to penetration sleeves with dissimilar metal welds. Plant operating experience has not identified any stress corrosion cracking associated with these welds. Visual examinations are augmented with surface examinations to manage cracking in the pressure retaining portions of the fuel transfer tube, fuel transfer tube enclosure, fuel transfer tube blind flange, dissimilar metal weld penetrations, and high-temperature piping penetrations. Surface examinations will be performed once during each 10-year interval. A one-time volumetric examination of metal liner surfaces that are inaccessible from one side will be performed if triggered by plant-specific operating experience. Sampling locations will be those susceptible to loss of thickness due to corrosion of the containment liner that is inaccessible from one side.

The ASME Section XI, Subsection IWE program manages aging of the steel liner of the concrete Containment. The *10 CFR Part 50, Appendix J* program (B2.1.32) manages loss of leak tightness, loss of sealing, and leakage through Containment. Containment seals and gaskets are included in the scope of the *10 CFR Part 50, Appendix J* program (B2.1.32). An evaluation of the acceptability of the inaccessible areas is completed whenever conditions are detected in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.

A review of 10 years of plant-specific operating experience associated with inaccessible areas from the ASME Section XI, Subsection IWE program did not identify any significant indications of corrosion.

Service Level 1 coatings are included in the scope of the *Protective Coating Monitoring and Maintenance* program (B2.1.36).

The *ASME Section XI, Subsection IWE* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *ASME Section XI, Subsection IWE* program is an existing program that, following enhancement, will be consistent, with NUREG-2191, Section XI.S1, ASME Section XI, Subsection IWE as modified by SLR-ISG-Structures-2020-XX, Updated Aging Management Criteria for Structures Portions of the Subsequent License Renewal Guidance.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Parameters Monitored/Inspected (Element 3); Detection of Aging Effects (Element 4); and Acceptance Criteria (Element 6)

1. Procedures will be revised to augment visual examinations with surface examinations (or other applicable technique) to manage cracking in the pressure retaining portions of the fuel transfer tube, fuel transfer tube enclosure, fuel transfer tube blind flange, dissimilar metal weld penetrations, and high-temperature piping penetrations. Surface examinations will be performed once during each 10-year interval.

Detection of Aging Effects (Element 4)

2. Procedures will be revised to perform a one-time volumetric examination of metal liner surfaces that are inaccessible from one side if triggered by plant-specific operating experience. The trigger for this supplemental examination is plant-specific occurrence or recurrence of measurable metal liner corrosion (base metal material loss exceeding 10% of nominal plate thickness) initiated on the inaccessible side or areas, identified since the date of issuance of the first renewed license. This supplemental volumetric examination consists of a sample of one-foot square locations that include both randomly-selected and focused areas most likely to experience degradation based on operating experience and/or other relevant considerations such as environment. Any identified degradation is addressed in accordance with the applicable provisions of the *ASME Section XI, Subsection IWE* program. The sample size, locations, and any needed scope expansion (based on findings) for this one-time set of volumetric examinations should be determined on a plant-specific basis to demonstrate statistically with 95% confidence that 95% of the accessible portion of the containment liner is not experiencing corrosion degradation with greater than 10% loss of nominal thickness.

Monitoring and Trending (Element 5)

3. Plant procedures will be revised to specify that successive inspections will be sequenced, evaluated, and re-examined in accordance with ASME Code, Section XI, Subsection IWE, Article IWE-2420. Examination results will be compared with recorded results of prior inservice examinations and evaluated for acceptance in accordance with ASME Code, Section XI, Subsection IWE, Article IWE-3120.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *ASME Section XI, Subsection IWE* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In September 1999, removal of a blister discovered in the Unit 2 containment liner protective coating revealed a corroded spot under the paint. Subsequent testing confirmed the hole to be through the liner. Removal of a portion of the liner revealed a piece of wood, which had been in contact with the liner. Ultrasonic testing (UT) examinations were made on an extended area on either side of the location. Based on an Engineering evaluation of these UT examination results, larger sections of the liner were removed, the wood was removed, the concrete was repaired, and the liner was repaired. Repairs and examinations of the repairs were completed prior to the end of the outage. Subsequently, a Type A Integrated Leak Rate Test was successfully performed.
2. In March 2010, during the ASME Section XI, Subsection IWE program general visual examination of the Unit 2 containment liner, one relevant condition was found, and six blisters of the Service Level I coating were observed that required supplemental examination. The relevant condition observed during the examination was several gouges/dents with signs of corrosion. The corrosion was not deep enough to affect the liner integrity. The paint blisters and the relevant condition regarding the gouges/dents were prepped and inspected prior to application of the coating system. Based on the surface preparation and the inspection, no liner integrity issues existed at these locations.
3. In June 2014, NRC Information Notice 2014-07 (IN 2014-07), “Degradation of Leak-Chase Channel Systems for Floor Welds of Metal Containment Shell and Concrete Containment Metallic Liner,” was evaluated for applicability. Consistent with the guidance in IN 2014-07, the containment basemat liner leak chase channel test connections are regarded as “Moisture Barriers”. General visual examinations of the moisture barriers in accessible areas are performed consistent with ASME Code, Section XI, Subsection IWE, Examination Category E-A, Item E1.30. No relevant conditions have been identified.
4. In March 2015, during performance of the containment structural inspection, minor general corrosion was observed at various locations around the containment steel liner and basemat interface. This corrosion was minor and did not affect containment integrity. Adjacent coatings around the areas of surface corrosion were well adhered and evaluated as acceptable. No further actions were required to be taken.

5. In March 2016, Engineering examination of the containment liner to basemat interface was completed. Eleven areas were identified with minor surface corrosion. All indications were non-relevant IWE conditions and were repaired as Service Level 1 coatings.
6. In March 2016, during the Unit 2 ASME Section XI, Subsection IWE program inspection, a bulge and staining were identified on the containment liner in the electrical penetration area. The stain was visually examined and found to be discoloration caused by a brown substance that had dripped from above. The brown substance was flaking in some areas giving an appearance of corrosion. The examination determined that no corrosion was present in this area and the liner coating was intact. The bulge was evaluated by Engineering and determined not to affect the integrity of the liner. No further actions were required.
7. In 2016, Regulatory Issue Summary 2016-07 (RIS 2016-07), "Containment Shell or Liner Moisture Barrier Inspection," was evaluated for applicability. A moisture barrier is not employed at the liner/containment floor slab interface. However, supplemental exams (VT-3) are performed at the liner/floor slab interface as well as the floor slab concrete joints in accordance with ASME Code, Section XI, Subsection IWE, Examination Category E-A, Item E1.11.
8. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion was reached that no performance deficiencies or learning opportunities were identified for the ISI Program - Containment Inspection AMA (UFSAR Section 18.2.12) related to the ASME Section XI, Subsection IWE program.
9. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.
10. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the ISI Program - Containment Inspection AMA (UFSAR Section 18.2.12) related to the ASME Section XI, Subsection IWE program.

11. In April 2019, an effectiveness review was performed on the ISI Program - Containment Inspection AMA (UFSAR Section 18.2.12) that include periodic inspections for aging management to ensure the continuing capability of Containment structures to meet their intended functions consistent with the current licensing basis. The AMAs were evaluated against the performance criteria identified in NEI 14-12, "Aging Management Program Effectiveness." No gaps were identified by the effectiveness review related to the ASME Section XI, Subsection IWE program.

The above examples of operating experience provide objective evidence that the *ASME Section XI, Subsection IWE* program includes activities to perform visual examinations (general visual, VT-3, VT-1) and limited volumetric examinations (ultrasonic thickness measurement) to manage the aging effects of cracking, loss of material, loss of sealing, loss of preload, and loss of leak tightness for the Containment liner plate and its integral attachments within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *ASME Section XI, Subsection IWE* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *ASME Section XI, Subsection IWE* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *ASME Section XI, Subsection IWE* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.30 ASME Section XI, Subsection IWL

Program Description

The *ASME Section XI, Subsection IWL* program is an existing condition monitoring program that manages the following aging effects for containment concrete:

- Cracking
- Cracking and distortion
- Cracking; loss of bond; and loss of material (spalling, scaling)
- Cracking; loss of material
- Increase in porosity and permeability; cracking; loss of material (spalling, scaling)
- Increase in porosity and permeability; loss of strength
- Loss of material (spalling, scaling) and cracking

The design of the reinforced concrete Containment does not utilize prestressing tendons.

For the current 10-year inspection interval (third quarter 2017 through second quarter 2027), IWL Containment Inservice Inspections (CISIs) are performed consistent with the 2007 Edition of ASME Code, Section XI, Subsection IWL (including 2008 addenda), supplemented with the applicable requirements of 10 CFR 50.55a(b)(2). In conformance with 10 CFR 50.55a(g)(4)(ii), the Containment inservice inspection program will be updated during each successive 120-month inspection interval to comply with the requirements of the latest edition and addenda of the Code specified 12 months before the start of the inspection interval.

The program includes the accessible areas of the Containment concrete dome and cylinder walls. When conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas, the conditions are evaluated to determine the acceptability of such inaccessible areas. The primary inspection method is visual examination (VT-1C, VT-3C) using the evaluation criteria provided in Chapter 5 of ACI 349.3R, “Evaluation of Existing Nuclear Safety-Related Concrete Structures.” Photography and its variations may be used to trend aging effects such as cracking, spalling, delamination, pop-outs, or other age-related concrete degradation as illustrated in ACI 201.1R, “Guide for Conducting a Visual Inspection of Concrete in Service.”

Plant procedures specify quantitative acceptance criteria for concrete surfaces that are consistent with the second-tier acceptance criteria provided in Chapter 5 of ACI 349.3R. The Responsible Engineer evaluates inspection results that do not meet established acceptance standards to ensure that corrective action is implemented before loss of intended functions.

Concrete inspectors are trained to identify changes that could be indicative of Alkali-Silica Reaction (ASR). If indications of ASR development are identified, the evaluation considers the potential for ASR development in concrete that is within the scope of the *ASME Section XI, Subsection IWL* program (B2.1.30), the *Structures Monitoring* program (B2.1.34), or the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.35).

The *ASME Section XI, Subsection IWL* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *ASME Section XI, Subsection IWL* program is an existing program that is consistent with NUREG-2191, Section XI.S2, ASME Section XI, Subsection IWL.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *ASME Section XI, Subsection IWL* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In September 1999, removal of a blister discovered in the Unit 2 Containment liner protective coating revealed a corroded spot under the paint. Subsequent testing confirmed the hole to be through the liner. Removal of a portion of the liner revealed a piece of wood, which had been in contact with the liner. Ultrasonic testing (UT) examinations were performed on an extended area on either side of the location. Based on an Engineering evaluation of these UT examination results, larger sections of the liner were removed, the wood was removed, the concrete was repaired, and the liner was repaired. Repairs and examinations of the repairs were completed prior to the end of the outage. Subsequently, a Type A Integrated Leak Rate Test was successfully performed.
2. In August 2001, *ASME Section XI, Subsection IWL* program inspections identified six pieces of embedded wood on the outer surfaces of the Containment concrete. An Engineering evaluation was made, and a repair plan was developed and implemented. The wood pieces

were removed, and the concrete was repaired. Steel reinforcing bars were not exposed. One of the wood pieces extend beyond the first layer of reinforcing bars to the steel liner and became a Code repair. After removal of the wood, the liner was cleaned and examined. UT examinations verified the liner was still at design thickness. The concrete surface within the hole was examined and no reinforcing bars were exposed. The area was repaired, and an engineering assessment concluded structural integrity and leak-tightness were not compromised by the embedded wood. A Containment pressure test was not required since the Containment was determined to meet its design function.

3. In July 2011, a five-year *ASME Section XI, Subsection IWL* program inspection of the Unit 1 Containment concrete surface was performed. Twenty-five areas were identified for evaluation or further investigation. The Responsible Civil Engineer inspected these items to assess the condition and to determine the appropriate course of action. Six of these areas were determined to be inconsequential, requiring no further actions. Eighteen of these areas required repair but were considered non-structural and did not extend beyond the face of primary reinforcement. As such, they did not require code repairs. One area did extend beyond the concrete cover and had exposed primary reinforcement. This required an ANII approved Repair/Replacement plan prior to making and ASME Code, Section XI, Subsection IWL code repair. The plan was generated and the Code repair completed. Based on an Engineering evaluation of these inspection findings, the Containment was determined to meet its design function.

4. In July 2011, a five-year *ASME Section XI, Subsection IWL* program inspection of the Unit 2 Containment concrete surface was performed. Twenty-five areas were identified for evaluation or further investigation. The Responsible Civil Engineer inspected these items to assess the condition and to determine the appropriate course of action. Five of these areas were determined to be inconsequential, requiring no further actions. Twenty of these areas required repair but were considered non-structural and did not extend beyond the face of primary reinforcement. Repairs were completed in accordance with station procedures. No areas required an ASME Code, Section XI, Subsection IWL Code repair. Based on an Engineering evaluation of these inspection findings, the Containment was determined to meet its design function.

5. In September 2011 during the *ASME Section XI, Subsection IWL* program inspection of the exterior concrete surfaces of the Unit 1 Containment, a spall/rock pocket was found on the dome. After the area was excavated to sound concrete, the excavation was evaluated by Engineering and found to extend beyond the concrete cover, exposing primary reinforcement. This required an ANII approved Repair/Replacement plan prior to making an ASME Code, Section XI, Subsection IWL code repair. The plan was generated and the Code repair completed.

6. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion was reached that no performance deficiencies or learning opportunities were identified for the ISI Program - Containment Inspection AMA (UFSAR Section 18.2.12) related to the ASME Section XI, Subsection IWL program.
7. In the summer of 2016, a five-year IWL inspection of the Unit 1 Containment concrete surface was performed. Fifty-seven areas were identified for evaluation or further investigation. The Responsible Civil Engineer inspected these items to assess the condition and to determine the appropriate course of action. Eleven of these areas were determined to be inconsequential, requiring no further actions. Forty-six of these areas required repair but were considered non-structural and did not extend beyond the face of primary reinforcement. Repairs have been completed by work order. No areas required an ASME Code, Section XI, Subsection IWL Code repair. Based on an Engineering evaluation of these inspection findings, the Containment was determined to meet its design function.
8. In the summer of 2016, a five-year IWL inspection of the Unit 2 Containment concrete surface was performed. Forty-three areas were identified for evaluation or further investigation. The Responsible Civil Engineer inspected these items to assess the condition and to determine the appropriate course of action. Thirteen of these areas were determined to be inconsequential, requiring no further actions. Thirty of these areas required repair but were considered non-structural and did not extend beyond the face of primary reinforcement. Repairs have been completed by work order. No areas required an ASME Code, Section XI, Subsection IWL Code repair. Based on an Engineering evaluation of these inspection findings, the Containment was determined to meet its design function.
9. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

10. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the ISI Program - Containment Inspection AMA (UFSAR Section 18.2.12) related to the *ASME Section XI, Subsection IWL*program.
11. In April 2019, an effectiveness review was performed on the ISI Program - Containment Inspection AMA (UFSAR Section 18.2.12) that include periodic inspections for aging management to ensure the continuing capability of Containment structures to meet their intended functions consistent with the current licensing basis. The AMAs were evaluated against the performance criteria identified in NEI 14-12, "Aging Management Program Effectiveness." No gaps were identified by the effectiveness review related to the *ASME Section XI, Subsection IWL* program.

The above examples of operating experience provide objective evidence that the *ASME Section XI, Subsection IWL* program includes activities to perform visual examinations (general visual, VT-1C) to manage aging effects for containment concrete within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *ASME Section XI, Subsection IWL* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *ASME Section XI, Subsection IWL* program will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *ASME Section XI, Subsection IWL* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.31 ASME Section XI, Subsection IWF

Program Description

The *ASME Section XI, Subsection IWF* program is an existing condition monitoring program that manages cracking, loss of material, loss of mechanical function, and loss of preload for supports of Classes 1, 2, and 3 piping and components. There are no Class MC supports.

During the fifth inservice inspection interval (May 1, 2019 through April 30, 2029) for Unit 1 and the fourth inspection interval (December 14, 2010 through December 13, 2020) for Unit 2, inspections of supports for Class 1, 2, and 3 piping and components are performed consistent with the 2013 and 2004 editions, respectively, of ASME Code, Section XI, as approved in 10 CFR 50.55a. In conformance with 10 CFR 50.55a(g)(4)(ii), the inservice inspection program is updated during each successive 120-month inspection interval to comply with the requirements of the latest edition and addenda of the Code specified 12 months before the start of the inspection interval. ASME Code editions and addenda will be used consistent with the provisions of 10 CFR 50.55a during the subsequent period of extended operation.

Supports for Class 1, 2, and 3 piping and components are selected for examination per the requirements of ASME Code, Section XI, Subsection IWF. Acceptance standards are specified in ASME Code, Section XI, Subsection IWF, Subarticle IWF-3400. The scope of the inspection for supports is based on class and total population as defined in Table IWF-2500-1. When a component support requires corrective measures in accordance with the provisions of Article IWF-3000, that support is reexamined during the next inspection period. When the reexaminations do not require additional corrective measures during the next inspection period, the inspection schedule reverts to the requirements of the original inspection program.

Component support examinations that detect flaws or relevant conditions exceeding the acceptance criteria of Subarticle IWF-3400 are extended to include additional examinations in accordance with Subarticle IWF-2430. The *ASME Section XI, Subsection IWF* program provides a systematic method for periodic examination of supports for Class 1, 2, and 3 piping and components. The primary inspection method is visual examination. The instructions and acceptance criteria for the visual examinations (VT-3) are included in existing procedures.

If a component support does not exceed the acceptance standards of Subarticle IWF-3400, but is electively repaired to as-new condition, then the sample is increased or modified to include another support that is representative of the remaining population of supports that were not repaired.

The requirements of Subsection IWF are supplemented to include monitoring of high-strength bolting (actual measured yield strength greater than or equal to 150 kilo-pounds per square inch (ksi) or 1,034 megapascals (MPa) and greater than one inch nominal diameter), with volumetric examination comparable to that of ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 to detect cracking in addition to the VT-3 examination. In each 10-year period during the subsequent period of extended operation, a representative sample of bolts will be inspected. The sample will be 20% of the population (for a material/environment combination) up to a maximum of 19 bolts per unit.

Procedures include preventive actions to ensure bolting integrity for replacement and maintenance activities by specifying proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. For structural bolting consisting of ASTM A325 and ASTM A490 bolts, preventive actions for storage, lubricant selection, and bolting and coating material selection are consistent with Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts.” Twist-off type ASTM F1852 and ASTM F2280 bolts are not specified or stocked for use.

This program includes a one-time inspection within five years prior to entering the subsequent period of extended operation 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 *ASME Section XI, Subsection IWF* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *ASME Section XI, Subsection IWF* program is an existing program that, following enhancement, will be consistent, with NUREG-2191, Section XI.S3, ASME Section XI, Subsection IWF.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Scope of Program (Element 1)

1. 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 exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.

Parameters Monitored/Inspected (Element 3) and Detection of Aging Effects (Element 4)

2. Procedures will be revised to specify that, for high-strength bolting greater than one inch nominal diameter within the scope of the *ASME Section XI, Subsection IWF* program, volumetric examination comparable to that of ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 will be performed to detect cracking in addition to the VT-3 examination. In each 10-year period during the subsequent period of extended operation, a representative sample of 20% of the population or a maximum of 19 high-strength bolts per unit will be inspected for IWF supports located in an “air” environment.

Detection of Aging Effects (Element 4)

3. Procedures will be revised to specify a one-time inspection within five years prior to entering the subsequent period of extended operation 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.

Monitoring and Trending (Element 5)

4. Procedures will be revised to require that if a component support does not exceed the acceptance standards of IWF-3400 but is 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.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *ASME Section XI, Subsection IWF* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In February 2009, Information Notice 2009-04 (IN 2009-04), “Age-Related Constant Support Degradation,” was issued to identify possible age-related degradation of mechanical constant supports that may adversely impact design stresses on piping systems. As stated in IN 2009-04, physical condition of the constant supports is visually examined as required by ASME Code, Section XI, Subsection IWF, which requires inspecting a certain number of supports every outage. The hot or cold settings of constant load supports are monitored as required by IWF-3410(a). As identified in IWF-3122.2, improper hot or cold settings for constant load supports are adjusted and re-examined in accordance with IWF-2200.

2. In January 2010, a potential concern with the adequacy of the seismic supports for the discharge piping of the Unit 1 '3B' motor-driven auxiliary feedwater pump was identified during a NRC inspection of the motor-driven auxiliary feedwater pump house. The immediate support for the discharge pipe had a slight gap between the pipe and support. A condition report was initiated and the non-conforming condition was resolved by adding shims. An extent of condition review was performed, which required walkdowns of additional supports for similar Unit 1 and Unit 2 piping. Degraded or non-conforming conditions were identified and entered into the Corrective Action Program for similar supports, and actions were taken to address the non-conforming conditions.
3. In September 2011, as a result of owner elected examinations in response to the August 2011 seismic event, a loose bolt was identified on a spring hanger for a safety injection system pipe support. This deficiency was evaluated as having no impact on the ability of the support to perform its design function and the bolt was tightened.
4. In October 2011, while performing a VT-3 examination on a spring hanger for Class 1 reactor coolant system piping, a nut on the upper rod-eye support bracket horizontal bolt was found to be loose. The support was evaluated and determined to be fully able to perform its design function, and the spring hanger was at its appropriate cold load setting. The nut was tightened in accordance with station procedures.
5. In October 2011, inspections were performed on all six of each Unit’s reactor vessel sliding feet supports. Engineering determined the supports to be adequate and fully capable of performing the intended design functions (permit thermal growth and restrain the feet in a lateral and vertical direction). There were no rejectable indications identified. Additional non-destructive examinations were performed on the Unit 1 ‘B’ loop cold leg reactor vessel sliding foot to address concerns regarding a potential crack. This included a visual (VT-1) examination and magnetic particle examination on both the left and right side hold down block in the area of concern. The additional examinations showed no evidence of surface indications.
6. In April 2012, during performance of an ASME Code, Section XI VT-3 examination for a Class 1 reactor coolant system 3/4-inch piping support, the pipe clamp was found to have excessive corrosion on the bottom side of the clamp. The condition was reviewed by Engineering and it was determined that the condition did not impact the ability of the snubber to perform its design basis function and the clamp was determined to be acceptable without the need for replacement.
7. In April 2013, during the refueling outage, a constant spring on the 16-inch feedwater line supplying the Unit 2 '1A' steam generator was found with the travel indicator out of adjustment for its cold displacement setting. The travel was adjusted to the proper cold setting and final VT-3 visual examination was performed under the ISI program.

8. In September 2014, during the VT-3 visual inspection of an anchor on chemical and volume control system Class 1 pipe support, one of the four bolts holding down the top plate of the anchor was found to have a nut that was backed off by 0.1-inch. The support was being inspected under the ASME Code Section XI program. Engineering evaluated the as found condition and concluded that the anchor was fully capable of performing its design basis function, for all load cases, including seismic and thermal loading. However, the bolt was determined to be excessively long and was replaced with a bolt which was a better length for the support.
9. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion was reached that no performance deficiencies or learning opportunities were identified for the ISI Program - Component and Component Support Inspections AMA (UFSAR Section 18.2.11) related to inspection of *ASME Section XI, Subsection IWF* program supports.
10. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.
11. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the ISI Program - Component and Component Support Inspections AMA (UFSAR Section 18.2.11) related to inspection of *ASME Section XI, Subsection IWF* program supports.
12. In April 2019, an effectiveness review was performed on the ISI Program - Component and Component Support Inspections AMA (UFSAR Section 18.2.11). The AMA was evaluated against the performance criteria identified in NEI 14-12, “Aging Management Program Effectiveness.” No gaps were identified by the effectiveness review related to the ASME Section XI, Subsection IWF program.

The above examples of operating experience provide objective evidence that the *ASME Section XI, Subsection IWF* program includes activities to perform visual examinations (VT-1, VT-3) and volumetric examinations to manage cracking, loss of material, loss of mechanical function, and loss of preload for supports of Classes 1, 2, and 3 piping and components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *ASME Section XI, Subsection IWF* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *ASME Section XI, Subsection IWF* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *ASME Section XI, Subsection IWF* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.32 10 CFR Part 50, Appendix J

Program Description

The *10 CFR Part 50, Appendix J* program is an existing performance monitoring program that manages cracking, loss of leak tightness, loss of material, loss of preload and loss of sealing. Leakage rates through the Containment pressure boundary are monitored, including the Containment liner, associated welds, penetrations, isolation valves, fittings, and other access openings to detect degradation of the Containment pressure boundary. Corrective actions are taken if leakage rates exceed acceptance criteria.

Leakage rate testing is performed in accordance with the regulations and guidance provided in 10 CFR Part 50, Appendix J, Option B; Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program;" and NEI 94-01, Revision 3-A, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J," and Section 4.1 "Limitations and Conditions for NEI TR 94-01, Revision 2" of the NRC Safety Evaluation Report in NEI 94-01, Revision 2-A; and subject to the requirements of 10 CFR Part 54.

Containment leak rate tests are performed to verify that leakage through the Containment, and systems and components penetrating the Containment, remains below Technical Specification allowable limits. An integrated leak rate test is performed during unit shutdown at an interval based on the historical performance of the overall Containment system. A general visual inspection of accessible interior and exterior surfaces of the Containment structure is conducted at intervals that comply with 10 CFR Part 50, Appendix J. Local leak rate tests are performed on Containment access penetrations and Containment isolation valves at intervals that comply with 10 CFR Part 50, Appendix J, Option B.

Visual inspections of the accessible interior and exterior surfaces of the Containment structure and components, performed by the *ASME Section XI, Subsection IWE* program (B2.1.29) and the *ASME Section XI, Subsection IWL* program (B2.1.30), augment the *10 CFR Part 50, Appendix J* program (B2.1.32) leakage rate testing and detect evidence of structural degradation that may affect the Containment structure leakage integrity.

Aging effects associated with components excluded from leak rate testing are managed by the:

- *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1)
- *ASME Section XI, Subsection IWE* program (B2.1.29)
- *ASME Code Class 1 Small-Bore Piping* program (B2.1.22)
- *Boric Acid Corrosion* program (B2.1.4)
- *External Surfaces Monitoring of Mechanical Components* program (B2.1.23)
- *Flow-Accelerated Corrosion* program (B2.1.8)
- *One-Time Inspection* program (B2.1.20)
- *Water Chemistry* program (B2.1.2)

NUREG-2191 Consistency

The *10 CFR Part 50, Appendix J* program is an existing program that is consistent with NUREG-2191, Section XI.S4, 10 CFR Part 50, Appendix J.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *10 CFR Part 50, Appendix J* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In March 2009, during a Containment Type B test of the equipment hatch to Containment liner interface, the as-found leak rate was determined to require an Engineering evaluation. The equipment hatch gasket grooves were inspected and cleaned, and the o-rings reinstalled. Subsequent Containment Type B testing was satisfactory.
2. In June 2014, a license amendment request (LAR) was submitted (ADAMS Accession No. ML14183B318) to implement Option B of 10 CFR 50 Appendix J for both Units 1 and 2. The LAR included as-found results of the three previous Type A tests for each unit. For Unit 1, the results were: October 2007 - 0.557 of La; April 1993 - 0.34 of La; June 1989 - 0.63 of La. For Unit 2, the results were: October 1999 - 0.6138 of La; October 1990 - 0.37 of La, April 1989 - 0.49 of La.

3. In January 2015, the results of the October 2014 Unit 2 Type A test were submitted in response to a request for additional information (ADAMS Accession No. ML15034A353). The total as-found Containment leakage was 0.0292 of La.
4. In June 2015, the NRC issued a Safety Evaluation Report (SER) (ADAMS Accession No. ML15133A381) and amended the licenses for Units 1 and 2 to extend the Type A test frequency to fifteen years. In the SER, the NRC found that the results of the testing and inspection programs demonstrated acceptable performance of the Containments and demonstrated that the structural and leak-tight integrity of the Containment structure is adequately managed. The NRC further found that Containment structural and leak-tight integrity will continue to be maintained through an adequate Containment leakage rate testing program, if the current interval is extended to 15 years for Type A testing and 75 months for Type C testing.
5. In April 2016, a valve failed Type C testing with a high leak rate. Maintenance inspected the valve and found that the soft seating surface was worn in a one inch section. The valve seat was replaced and was tested satisfactorily.
6. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion was reached that no performance deficiencies or learning opportunities were identified for the ISI Program - Containment Inspection AMA (UFSAR Section 18.2.12) related to Containment IWE and IWL inspections.
7. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.
8. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the ISI Program - Containment Inspection AMA (UFSAR Section 18.2.12) related to Containment IWE and IWL inspections.

9. In April 2019, an effectiveness review was performed on the ISI Program - Containment Inspection AMA (UFSAR Section 18.2.12) that includes Containment IWE and IWL inspections among its inspection activities. The AMA was evaluated against the performance criteria identified in NEI 14-12, “Aging Management Program Effectiveness.” No gaps were identified by the effectiveness review related to Containment IWE and IWL inspections.

The above examples of operating experience provide objective evidence that the *10 CFR Part 50, Appendix J* program includes visual inspections and leak rate tests to identify cracking, loss of leak tightness, loss of material, loss of preload, and loss of sealing for Containment pressure boundary components, including the liner, penetrations, associated welds, access openings, seals, and gaskets within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *10 CFR Part 50, Appendix J* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *10 CFR Part 50, Appendix J* program will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *10 CFR Part 50, Appendix J* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.33 Masonry Walls

Program Description

The *Masonry Walls* program is an existing condition monitoring program that manages cracking, loss of material, and loss of material (spalling and scaling) for masonry walls. The *Masonry Walls* program is implemented as part of the *Structures Monitoring* program (B2.1.34).

The *Masonry Walls* program consists of inspections, consistent with Inspection and Enforcement Bulletin 80-11 (IEB 80-11), “Masonry Wall Design,” and plant-specific monitoring proposed by Information Notice 87-67 (IN 87-67), “Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 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.

The *Masonry Walls* program relies on periodic visual inspections, conducted by qualified personnel at a frequency not to exceed five years, to monitor and maintain the condition of masonry walls within the scope of subsequent license renewal so that the established evaluation basis for each masonry wall remains valid during the subsequent period of extended operation. Qualifications for personnel performing inspections and evaluations are consistent with ACI 349.3R, “Evaluation of Existing Nuclear Safety-Related Concrete Structures.” Inspections are performed and results evaluated consistent with applicable industry documents to ensure that a loss of intended function does not occur. Conditions found to impact the intended function of the masonry wall or invalidate its evaluation basis are entered into the Corrective Action Program. Masonry walls that are considered fire barriers are also managed by the *Fire Protection* program (B2.1.15). Steel elements of masonry walls are visually inspected by the *Structures Monitoring* program (B2.1.34).

NUREG-2191 Consistency

The *Masonry Walls* program is an existing program that is consistent with NUREG-2191, Section XI.S5, Masonry Walls.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Masonry Walls* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In March 2009, a crack in the Turbine Building south wall was located in a vertical control joint designed into the masonry block wall to relieve any settlement or other movement in this long run of block wall. Engineering determined that the crack did not degrade the wall structurally. Biannual action items were assigned to re-inspect the cracked area of the wall for a minimum of the next two years. Over that ensuing two-year inspection period, no crack growth or degrading trends were noted. Since the crack had remained dormant throughout the period, no structural repairs were determined to be necessary. The six-month inspections were discontinued and the normal five-year inspection frequency was resumed.
2. In August 2011, hairline cracks that appeared to be cosmetic were identified on the south wall of the control rod drive Motor-Generator Set House. The cracks were within acceptance criteria (< 0.06 inch). The Responsible Engineer determined the cracks were acceptable and there were no structural concerns. The Appendix R Coordinator evaluated the cracks and determined they were in alignment with the guidance of fire barrier and EQ criterion. The functional requirements for this barrier were determined by Engineering to not be affected by this finding. A work order was initiated and the cracks were repaired.
3. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion was reached that no performance deficiencies or learning opportunities were identified for the Civil Engineering Structural Inspection AMA (UFSAR Section 18.2.6) related to masonry walls inspections.
4. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.
5. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the Civil Engineering Structural Inspection AMA (UFSAR Section 18.2.6) related to masonry walls inspections.

6. In April 2019, an effectiveness review was performed on the Civil Engineering Structural Inspection AMA (UFSAR Section 18.2.6) that includes masonry walls among its inspection activities. The AMA was evaluated against the performance criteria identified in NEI 14-12, “Aging Management Program Effectiveness.” No gaps were identified by the effectiveness review related to masonry walls inspections.

The above examples of operating experience provide objective evidence that the *Masonry Walls* program includes activities to perform visual inspections to manage cracking, loss of material, and loss of material (spalling and scaling) for masonry walls within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Masonry Walls* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Masonry Walls* program will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Masonry Walls* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.34 Structures Monitoring

Program Description

The *Structures Monitoring* program is an existing condition monitoring program that manages aging of the structures and components that are within the scope of subsequent license renewal by managing the following aging effects:

- Cracking
- Cracking and distortion
- Cracking, loss of bond, and loss of material (spalling, scaling)
- Cracking, loss of material
- Increase in porosity and permeability, cracking, loss of material (spalling, scaling)
- Increase in porosity and permeability, cracking, loss of strength
- Loss of material
- Loss of material (spalling, scaling) and cracking
- Loss of mechanical function
- Loss of preload
- Loss of sealing
- Reduction in concrete anchor capacity
- Reduction of foundation strength and cracking
- Reduction or loss of isolation function

The *Structures Monitoring* program implements the requirements of 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” consistent with guidance of U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide 1.160 (RG-1.160), “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” and Nuclear Management and Resources Council 93-01, “Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.”

The *Structures Monitoring* program relies on periodic visual inspections to monitor and maintain the condition of structures and structural components. Inspections are conducted by qualified personnel at a frequency not to exceed five years. The interval between successive recurring inspections may be decreased based on conditions discovered in previous inspections. Evaluation of inspection results includes consideration of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. Inaccessible areas are assessed for aging and opportunistically inspected when made accessible by other plant activities.

For concrete and associated components, ACI-349.3R, “Evaluation of Existing Nuclear Safety-Related Concrete Structures,” and other applicable industry documents are used as guidance for the inspections, inspector qualifications, and evaluation of inspection results. The inspection program for structural steel is similar to the concrete program and is based on the guidance provided by the American Institute of Steel Construction (AISC) Specification for Structural Steel Buildings and Code of Standard Practice. For earthen structures, evaluation of inspection results is performed by a qualified civil/structural engineer.

Procedures include preventive actions to ensure structural bolting integrity for replacement and maintenance activities by specifying proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. For structural bolting consisting of ASTM A325 and ASTM A490 bolts, preventive actions for storage, lubricant selection, and bolting and coating material selection are consistent with Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts.” Twist-off type ASTM F1852 and ASTM F2280 bolts are not specified or stocked for use.

In order to evaluate the potential of water to cause degradation of concrete, samples of groundwater are taken at intervals not to exceed five years. The water chemistry is evaluated, and should the results of water testing indicate potentially harmful levels of substances such as chlorides > 500 ppm, sulfates > 1,500 ppm, or a pH < 5.5, excavation and examination of buried concrete surfaces may be necessary. Groundwater monitoring has shown the groundwater to be non-aggressive. There have been no indications of concrete degradation due to aggressive groundwater anywhere in the plant.

For surfaces provided with protective coatings, observation of the condition of the coating is an effective method for identifying the absence of degradation of the underlying material. Therefore, coatings on structures within the scope of the *Structures Monitoring* program are inspected only as an indication of the condition of the underlying material.

Plant-specific OE has identified loss of material due to pitting or crevice corrosion or cracking of stainless steel piping components exposed to air or condensation in an underground environment. There has been no documented loss of material due to pitting or crevice corrosion or cracking of stainless steel or aluminum structural components within the scope of the Structures Monitoring Program. The potential for loss of material or cracking of stainless steel and aluminum structural components exposed to air or condensation environments will be managed by the Structures Monitoring program.

Aluminum and stainless steel structural components such as louvers, cable trays, conduits, and structural supports will be monitored for cracking due to SCC that could lead to the reduction or loss of their intended function.

Concrete inspection results will be evaluated to identify changes that could be indicative of Alkali-Silica Reaction (ASR) development. If indications of ASR development are identified, the evaluation considers the potential for ASR development in concrete that is within the scope of the *ASME Section XI, Subsection IWL* program (B2.1.30), the *Structures Monitoring* program (B2.1.34), or the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.35).

Structural sealants, seismic gap joint filler, vibration isolation elements, and other elastomeric materials will be monitored for cracking, loss of material, and hardening. These elastomeric elements are acceptable if the observed loss of material, cracking, and hardening will not result in a loss of intended function.

Visual inspection of elastomeric elements will be supplemented by tactile inspection to detect hardening if the intended function is suspect.

The Spent Fuel Pool level is monitored by a level switch that will actuate if the water level decreases to six inches below normal water level. Instrumentation provided gives local indication in the Fuel Building and the Auxiliary Building and remote indications and alarms in the main control room (UFSAR, Section 9.1.3.5). Leakage from the Spent Fuel Pool telltale drains is evaluated by a separate plant procedure. A review of recent telltale drain monitoring reports by the Responsible Engineer shows acceptable leakage rates. However, leakage from three of the telltale drains have shown a decreasing trend that could potentially indicate blockages in the drains. Performance of a borescope inspection on the Spent Fuel Pool telltale drains has been initiated.

The *Masonry Walls* program (B2.1.33) and the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.35) are implemented as part of this program.

NUREG-2191 Consistency

The *Structures Monitoring* program is an existing program that, following enhancement, will be consistent, with NUREG-2191, Section XI.S6, Structures Monitoring.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Scope of Program (Element 1)

1. Procedures will be revised to include inspection of the following structures that are within the scope of subsequent license renewal: Administration Building (aka Office Building), Decontamination Building, Domestic Water Treatment Building, Heater Boiler Room,

Maintenance Building, New Fuel Receiving Building, Waste Disposal (Clarifier) Building, Waste Solids Building, 17-ton Carbon Dioxide tank foundation, and Backup 34.5 kV Circuit Power Poles (Switchyard to the Reserve Station Service Transformers). Baseline inspections for the added structures will be performed under the enhanced program in order to establish quantitative inspection data prior to conduct of periodic inspections in the subsequent period of extended operation. The baseline inspections will include baseline inspections of the masonry walls in the Administration Building, Decontamination Building, Domestic Water Treatment Building, and the Maintenance Building.

Scope of Program (Element 1) and Parameters Monitored/Inspected (Element 3)

2. Procedures will be revised to specify that structural components inspected include structural bolting, anchor bolts and embedments, component support members, pipe whip restraints and jet impingement shields, transmission towers, panels and other enclosures, racks, sliding surfaces, sump and pool liners, electrical cable trays and conduits, tube tracks, trash racks associated with water-control structures, electrical duct banks, manholes, doors, penetration seals, seismic joint filler and other elastomeric materials.

Parameters Monitored/Inspected (Element 3); Detection of Aging Effects (Element 4); and Acceptance Criteria (Element 6)

3. Procedures will be revised to specify that aluminum and stainless steel structural components such as louvers, cable trays, conduits, and structural supports will be monitored for cracking due to SCC that could lead to the reduction or loss of their intended function.
4. Procedures will be revised to specify that elastomeric vibration isolators, structural sealants, and seismic joint fillers will be monitored for cracking, loss of material, and hardening that could lead to the reduction or loss of their intended function. Visual inspection of elastomeric elements is supplemented by tactile inspection to detect hardening if the intended function is suspect.

Parameters Monitored/Inspected (Element 3) and Acceptance Criteria (Element 6)

5. Procedures will be revised to specify that accessible sliding surfaces will be monitored for indications of excessive loss of material due to corrosion or wear and debris or dirt that could restrict or prevent sliding of the surfaces.

Corrective Actions (Element 7)

6. Procedures will be enhanced to specify that evaluations of neutron shield tank findings consider its structural support function for the reactor pressure vessel.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Structures Monitoring* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In July 2009, a broken pipe support U-bolt was discovered on the emergency diesel generator lube oil pump discharge line. A design change was installed to modify the piping and support configuration to isolate the emergency diesel generator lube oil piping and its supports from the radiator enclosure structure, which subjects the piping and supports to high cyclical loads.

2. In December 2010, during the inspection of the Safeguards Valve Pit Valves, active groundwater leakage was observed in the Safeguards Valve Pits for both units. Groundwater had accumulated on the floor of the valve pit with calcium buildup occurring under the pipe.

   A 2006 Engineering evaluation indicated the preferred corrective action to eliminate the leakage was grout injection. The grout injections did not prevent groundwater leakage from reoccurring. Some leakage, calcium buildup, residue, and discoloration were identified on various piping, but an Engineering evaluation did not note any concerns with the pipe welds following the grout injections. The conditions noted on the pipes and the calcium deposits were determined to be a housekeeping issue. New groundwater diversion devices (drip trays) and temporary catch containers were installed to collect groundwater in-leakage.

3. In December 2015, a design change was approved to address degradation of the precast concrete poles supporting the 3-phase buses that run overhead from the Turbine Building to the Reserve Service Station Transformers. This degradation included large open cracks and evidence of alkali-silica reaction (ASR). The design change is replacing 14 of the 17 concrete poles with new steel poles and installing a carbon fiber reinforced polymer wrap for the full length of the remaining three poles. These poles were manufactured off-site utilizing materials and mix designs that are different from other concrete structures. The existence of ASR in these components is not indicative of this aging mechanism occurring in any other structure.

4. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion reached was that performance deficiencies or learning opportunities were identified for the Infrequently Accessed Area Inspection Activities AMA (UFSAR Section 18.1.2). Three areas listed in the

Infrequently Accessed Area Inspection AMA were not listed as Infrequently Accessed Areas in UFSAR Section 18.1.2. The areas consisted of the following:

- Manholes containing equipment or power and control cables for safety-related components and components associated with the five regulated events
- Service Water Pump House Underwater skirt
- Tunnel/passageway between Auxiliary Building and Decontamination Building

It was determined that these areas are being inspected, and no changes to UFSAR Section 18.1.2 were recommended.

Also in the May 2016 assessment, the conclusion was reached that performance deficiencies or learning opportunities were identified for the Civil Engineering Structural Inspection AMA (UFSAR Section 18.2.6). Plant procedures did not include dewatering and installation of shielding as activities to consider that could potentially result in a normally inaccessible structural component becoming accessible for inspection. Plant procedures were revised to include dewatering and installation of shielding as activities to consider that could potentially result in a normally inaccessible structural component becoming accessible for inspection.

Also in the May 2016 assessment, the conclusion was reached that performance deficiencies or learning opportunities were identified for the General Condition Monitoring Activities AMA (UFSAR Section 18.2.9). The General Condition Monitoring Activities AMA (UFSAR Section 18.2.9) did not consider or include missile doors and Containment pressure relief doors. Plant procedures were revised to include inspection of the doors, and the General Condition Monitoring Activities AMA (UFSAR Section 18.2.9) was revised to enhance the discussion of door inspections.

5. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.

6. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion reached was that an area for improvement or enhancement was identified for the Infrequently

Accessed Area Inspection Activities AMA (UFSAR Section 18.1.2). The evaluation to close the commitment for infrequently accessed areas did not provide details of inspector qualifications. In addition, there appeared to be a conflict between two license renewal commitments in UFSAR Table 18-1 (Commitments 9 and 17) concerning the inspection scope (use of representative samples). The license renewal commitments have been revised to discuss inspector qualifications and clarify the use of representative samples.

Also in the May 2017 assessment, the conclusion was reached that no areas for improvement or enhancements were identified for the Battery Rack Inspections AMA (UFSAR Section 18.2.2), the Civil Engineering Structural Inspection AMA (UFSAR Section 18.2.6), and the General Condition Monitoring Activities AMA (UFSAR Section 18.2.9) related to the *Structures Monitoring* program.

7. In April 2019, an effectiveness review was performed on the Infrequently Accessed Area Inspection Activities AMA (UFSAR Section 18.1.2), the Battery Rack Inspections AMA (UFSAR Section 18.2.2), the Civil Engineering Structural Inspection AMA (UFSAR Section 18.2.6), and the General Condition Monitoring Activities AMA (UFSAR Section 18.2.9) that include periodic inspections for aging management to ensure the continuing capability of civil engineering structures to meet their intended functions consistent with the current licensing basis. The AMAs were evaluated against the performance criteria identified in NEI 14-12, “Aging Management Program Effectiveness.” No gaps were identified by the effectiveness review related to the *Structures Monitoring* program.
8. From December 2006 to May 2019, samples of groundwater were analyzed quarterly. This monitoring showed the site groundwater to be non-aggressive (pH > 5.5, chlorides < 500 ppm, and sulfates < 1,500 ppm).
9. From February 2010 to June 2019, leakage from the Spent Fuel Pool telltale drains was evaluated every six months. A review of telltale drain monitoring reports shows acceptable leakage rates. Leakage from three of the telltale drains have shown a decreasing trend that could potentially indicate blockages in the drains. Performance of a borescope inspection of the Spent Fuel Pool telltale drains has been initiated. The Spent Fuel Pool level is monitored by a level switch that will actuate if the water level decreases to six inches below normal water level. Instrumentation gives local indication in the Fuel Building and the Auxiliary Building and remote indications and alarms in the main control room.
10. From April 2001 to September 2019, settlement of structures has been monitored every 184 days, as specified in the Technical Requirements Manual (TRM), Section 3.7.7. UFSAR Section 3.8.4.5.3 describes the Settlement Monitoring Program. The elevations of points located on structures and components at the Service Water Reservoir and at the main plant were monitored for settlement, beginning in 1975. Structures with minimal movement are no longer monitored. The structures and components that are currently being monitored are the

Service Water Reservoir, Service Water Pump House, service water lines, Service Water Valve House, Service Water Tie-in Vault, Service Building, and Main Steam Valve House. The initial baseline elevations for these structures and components are listed in UFSAR Table 3.8-15. If differences between observed values and baseline elevations exceed prescribed limits given in TRM Section B 3.7.7, appropriate action is taken in accordance with the Corrective Action Program. No settlements have been found to exceed the TRM limits.

The above examples of operating experience provide objective evidence that the *Structures Monitoring* program includes activities to perform visual inspections to identify aging effects for structures, structural supports, and structural commodities within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Structures Monitoring* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Structures Monitoring* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Structures Monitoring* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.35 Inspection of Water-Control Structures Associated with Nuclear Power Plants

Program Description

The *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program is an existing condition monitoring program, which is implemented as part of the *Structures Monitoring* program (B2.1.34), and manages the following aging effects:

- Cracking
- Cracking; loss of bond; loss of material (spalling, scaling)
- Increase in porosity and permeability; loss of strength
- Loss of material
- Loss of material (spalling, scaling) and cracking
- Loss of material; loss of form

The program consists of inspection and surveillance of raw-water control structures associated with emergency cooling systems or flood protection, which are the Discharge Tunnel, the Flood Protection Dike (flood wall west of Turbine Building), the Intake Structure, the Service Water Pump House, the Service Water Reservoir, the Service Water Valve House, the Circulating Water Intake Tunnel Header, and the Discharge Tunnel Seal Pit. Inspection and surveillance of the dam and water impoundments is in accordance with Regulatory Guide 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants." The *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program relies on periodic visual inspections conducted by qualified personnel at a frequency not to exceed five years to monitor and maintain the condition of water-control structures within the scope of subsequent license renewal. The program also includes structural steel and structural bolting associated with water-control structures.

Qualifications for personnel performing concrete inspections and evaluations are consistent with ACI 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures." Inspections are performed and inspection results evaluated consistent with applicable industry documents to ensure that a loss of intended function does not occur. Quantitative measurements are recorded for findings that exceed the acceptance criteria for applicable parameters monitored or inspected. Conditions found to impact the intended function of the water-control structure are documented and entered into the Corrective Action Program for evaluation, which will result in analysis, repair or replacement. Evaluation of the inspection results determines whether the discovered deficiency is minor and will not threaten the structure's ability to perform its intended function until the next scheduled inspection. A significant deficiency requires corrective action and/or more frequent monitoring to ensure that the structure will remain functional until the next regularly scheduled inspection.

In order to evaluate the potential of groundwater to cause degradation of concrete, samples of groundwater are taken at intervals not to exceed five years. The water chemistry is evaluated, and should the results of water testing indicate potentially harmful levels of substances, such as chlorides > 500 ppm, sulfates > 1,500 ppm, or a pH < 5.5, areas exposed to groundwater are assessed for potential aging.

Evaluation of inspection results includes consideration of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. Whenever inaccessible areas are excavated, exposed, or modified an opportunistic examination is performed.

Procedures include preventive actions to ensure bolting integrity for replacement and maintenance activities by specifying proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. For structural bolting consisting of ASTM A325 and ASTM A490 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection are consistent with Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts.” Twist-off type ASTM F1852 and ASTM F2280 bolts are not specified or stocked for use.

Concrete inspectors are trained to identify changes that could be indicative of Alkali-Silica Reaction (ASR). If indications of ASR development are identified, the evaluation considers the potential for ASR development in concrete that is within the scope of the *ASME Section XI, Subsection IWL* program (B2.1.30), the *Structures Monitoring* program (B2.1.34), or the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.35).

NUREG-2191 Consistency

The *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program is an existing program that, following enhancement, will be consistent, with NUREG-2191, Section XI.S7, Inspection of Water-Control Structures Associated with Nuclear Power Plants.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Scope of Program (Element 1)

1. Procedures will be revised to include the Circulating Water Intake Tunnel Header and the Discharge Tunnel Seal Pit within the scope of the program.

Detection of Aging Effects (Element 4)

2. Procedures will be revised to specify underwater inspections or dewatering to permit visual inspections for submerged structures, on a frequency not to exceed five years.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In March 2012, vegetation was observed on slopes at the Service Water Reservoir. During the biennial NRC inspection of the Service Water Reservoir, the Inspectors identified various locations of vegetative growth on the slopes of the Service Water Reservoir in the rip-rap. The growth was evaluated to be normal and did not pose a threat to the structural integrity of the Service Water Reservoir. The vegetation was removed.
2. In March 2013, concrete spalling and cracking was found at the Service Water Pump House. During efforts to remove loose concrete, additional concrete degradation was discovered. During the initial visual investigation, reinforcing steel was not visible. Upon further investigation and removal of additional loose concrete, it was determined that approximately eight linear feet of reinforcing steel was degraded and required repair. The average degradation of the rebar was 30% but did not prevent the Service Water Pump House from performing its design function. Repairs to the rebar and concrete were completed.
3. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion was reached that performance deficiencies or learning opportunities were identified for the Civil Engineering Structural Inspection AMA (UFSAR Section 18.2.6). Plant procedures did not include dewatering and installation of shielding as activities to consider that could potentially result in a normally inaccessible structural component becoming accessible for inspection. Plant procedures were revised to include dewatering and installation of shielding as activities to consider that could potentially result in a normally inaccessible structural component becoming accessible for inspection.

4. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.
5. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the Civil Engineering Structural Inspection AMA (UFSAR Section 18.2.6) related to the Inspection of Water-Control Structures Associated with Nuclear Power Plants program.
6. In April 2019, an effectiveness review was performed on the Civil Engineering Structural Inspection AMA (UFSAR Section 18.2.6), that includes periodic inspections for aging management to ensure the continuing capability of civil engineering structures to meet their intended functions consistent with the current licensing basis. The AMA was evaluated against the performance criteria identified in NEI 14-12, “Aging Management Program Effectiveness.” No gaps were identified by the effectiveness review related to the Inspection of Water-Control Structures Associated with Nuclear Power Plants program.
7. From December 2006 to May 2019, samples of groundwater were analyzed quarterly. This monitoring showed the site groundwater to be non-aggressive (pH > 5.5, chlorides < 500 ppm, and sulfates < 1,500 ppm).
8. From April 2001 to September 2019, settlement of structures has been monitored every 184 days, as specified in the Technical Requirements Manual (TRM), Section 3.7.7. UFSAR Section 3.8.4.5.3 describes the Settlement Monitoring Program. The elevations of points located on structures and components at the Service Water Reservoir and at the main plant were monitored for settlement, beginning in 1975. Structures for which minimal movement had occurred are no longer monitored. The in-scope water-control structures currently being monitored for settlement are the Service Water Reservoir, the Service Water Pump House, and the Service Water Valve House. The initial baseline elevations for these structures and components are listed in UFSAR Table 3.8-15. If differences between observed values and baseline elevations exceed prescribed limits given in TRM Section B 3.7.7, appropriate action is taken in accordance with the Corrective Action Program. No settlements have been found to have exceeded the TRM limits.

The above examples of operating experience provide objective evidence that the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program includes activities to perform visual inspections to identify aging effects for water-control structures within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.36 Protective Coating Monitoring and Maintenance

Program Description

The *Protective Coating Monitoring and Maintenance* program is an existing mitigative and condition monitoring program that manages loss of coating integrity of Service Level I coatings inside Containment. The program maintains and monitors the aging of Service Level 1 coatings consistent with RG 1.54 Revision 3, “Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants.”

Maintenance of coatings is consistent with ASTM D 5163-08, “Standard Guide for Establishing a Program for Condition Assessment of Coating Service Level I Coating Systems in Nuclear Power Plants.” The program includes activities to monitor and assess the material condition of Service Level I coatings applied to steel and concrete surfaces inside Containment by performing visual inspections with qualified inspectors to ensure there is no coating degradation. A pre-inspection review of the previous two containment coating condition assessment reports is performed prior to each refueling outage.

Maintenance of Service Level I coatings applied to carbon steel and concrete surfaces inside Containment (e.g., steel liner, structural steel, supports, penetrations, and concrete walls and floors) will serve to prevent or minimize the loss of material of carbon steel components due to corrosion and aids in decontamination, but these coatings are not credited for managing the effects of corrosion. This program ensures that the Service Level I coatings maintain adhesion so as to not affect the intended function of the emergency core cooling systems (ECCS) suction strainers.

The program also provides controls over the amount of unqualified coatings. Unqualified coating may fail in a way to affect the intended function of the ECCS suction strainers. Therefore, the quantity of degraded and unqualified coating is controlled and assessed periodically to ensure that the amount of unqualified coating in the primary containment is kept within acceptable design limits to support the post-accident operability of the ECCS.

The *Protective Coating Monitoring and Maintenance* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *Protective Coating Monitoring and Maintenance* program is an existing program that is consistent with NUREG-2191, Section XI.S8, Protective Coating Monitoring and Maintenance as modified by SLR-ISG-Structures-2020-XX, Updated Aging Management Criteria for Structures Portions of the Subsequent License Renewal Guidance.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Protective Coating Monitoring and Maintenance* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In March 2009, during the Unit 1 refueling outage walkdown of accessible levels of the Containment annulus and basement, coatings were observed to be in good condition with no coating blisters. The Containment annulus had small mechanical scratches that needed to be repaired in an area that was previously inaccessible due to scaffold storage. There were no observed rust pits, rust bloom, or any threats to the steel liner. Coating repairs were performed in March 2009.
2. In March 2010, during the Unit 2 refueling outage, Engineering performed a Containment coatings walkdown of the pressurizer rooms, RCP cubicles, and the loop rooms. Overall, the compartments were observed to be in good condition. Coating physical damage was observed on the top face of horizontal beams where equipment was dragged or placed. Coating repairs were performed in April 2010.
3. In April 2016, during the Unit 2 refueling outage Containment walkdown, a coatings blister was found on a conduit box on the cable penetration area. The blistered paint was removed, and the primer remained. The primer was intact and is a Coatings Service Level I qualified coatings material. Coating repairs were performed in September 2017.
4. In March 2018, during performance of the ASME Code, Section XI, Subsection IWE Unit 1 Containment inspection liner to concrete floor slab interface, engineering identified various locations where minor coating degradation occurred and coating repairs were required. Coating repairs were performed in March 2018.

The above examples of operating experience provide objective evidence that the *Protective Coating Monitoring and Maintenance* program includes activities to perform visual inspections to manage loss of coating integrity for Service Level 1 coatings within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Protective Coating Monitoring and Maintenance* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Protective Coating Monitoring and Maintenance* program will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Protective Coating Monitoring and Maintenance* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.37 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is an existing condition monitoring program that manages the aging effect of reduced electrical insulation resistance of accessible electrical cable and connection insulation material subject to an adverse localized environment.

An adverse localized environment is a condition in a limited plant area that is significantly more severe than the specified service environment for the electrical cables (power, control and instrumentation) and connections. The environment may be caused by temperature, radiation, or moisture. An adverse localized environment is significant if it could appreciably increase the rate of aging of a component or have an immediate adverse effect on operability.

The program performs a plant walkdown of in-scope structures to visually inspect for accessible cables and connections located in an adverse localized environment. Should an adverse localized environment be observed, accessible electrical cables and connections installed within that environment are visually inspected for the aging mechanisms associated with jacket surface and connection covering anomalies, such as embrittlement, discoloration, cracking, melting, swelling or surface contamination. These anomalies may indicate signs of reduced electrical insulation resistance.

A review of previously identified and mitigated adverse localized environments cumulative aging effects applicable to in-scope cable and connection electrical insulation will be performed.

The accessible electrical cable jacket and connection covering materials are to be free from unacceptable visual indications of surface anomalies which suggest that conductor insulation or connection covering degradation exists.

Visual inspection results that do not conclude that the cable and connection insulation material is free from unacceptable indications due to surface anomalies are evaluated in the Corrective Action Program.

Additionally, visual inspection findings may necessitate testing. Should testing be deemed necessary based on unacceptable visual indications of surface anomalies, a sample size of 20% of each cable and connection insulation material type found within the adverse localized environment with a maximum sample size of 25 will be tested. The following factors will be considered in the development of the cable and connection insulation test sample: environment including identified adverse localized environments (high temperature, high humidity, vibration, etc.), voltage level, circuit loading, connection type, location (high temperature, high humidity, vibration, etc.), and insulation material. Testing may include thermography and other proven condition monitoring test methods applicable to the cable and connection insulation. Testing as part of an existing maintenance, calibration or surveillance program may be credited. The technical basis for the sample selected is provided. The electrical cable and connection insulation material test results are to be within the acceptance criteria, as identified in the procedures.

The visual inspection frequency is based on Engineering evaluation and is performed at least once every ten years.

NUREG-2191 Consistency

The *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is an existing program that, following enhancement, will be consistent, with NUREG-2191, Section XI.E1, Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Parameters Monitored/Inspected (Element 3)

1. Procedures will be revised to add the requirement to identify adverse localized environments through plant operational experience reviews, communication with maintenance, operations, and radiation protection personnel, and the use of environmental surveys for determining each of the most limiting cable and connection electrical insulation plant environments (e.g., caused by temperature, radiation, moisture, or contamination.)
2. Procedures will be revised to add a list of structures/areas to perform/conduct the visual inspections of cables and connections.

Parameters Monitored/Inspected (Element 3) and Detection of Aging Effects (Element 4)

3. Procedures will be revised to add the requirement to perform a review of previously identified and mitigated adverse localized environments cumulative aging effects applicable to in-scope cable and connection electrical insulation.

Detection of Aging Effects (Element 4)

4. Procedures will be revised to add a description of testing methodology: Should testing be deemed necessary based on unacceptable visual indications of surface anomalies, a sample size of 20% of each cable and connection insulation material type found within the adverse localized environment with a maximum sample size of 25 will be tested. The following factors

will be considered in the development of the cable and connection insulation test sample: environment including identified adverse localized environments (high temperature, high humidity, vibration, etc.), voltage level, circuit loading, connection type, location (high temperature, high humidity, vibration, etc.), and insulation material. Testing may include thermography and other proven condition monitoring test methods applicable to the cable and connection insulation. Testing as part of an existing maintenance, calibration or surveillance program may be credited. The technical basis for the sample selected is provided.

Monitoring and Trending (Element 5)

5. Procedures will be revised to add the requirement that if anomalies are found during the visual inspection process, they will be addressed through the Corrective Action Program.

Acceptance Criteria (Element 6)

6. Procedures will be revised to add the requirement to verify that the test results for electrical cable and connection insulation material are to be within the acceptance criteria, as identified in the procedures.

Corrective Actions (Element 7)

7. Procedures will be revised to add the requirement to include the performance of an Engineering evaluation of unacceptable test results and visual indications of cable and connection electrical insulation abnormalities. The evaluation will consider the age and operating environment of the component, as well as the severity of the abnormality and whether such an abnormality has previously been correlated to degradation of cable or connection insulation. Corrective actions include, but are not limited to, testing, shielding, or otherwise mitigating the environment or relocation or replacement of the affected cables or connections. When an unacceptable condition or situation is identified, a determination is made as to whether the same condition or situation is applicable to additional in-scope accessible and inaccessible cables or connections (extent of condition).

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In December 2012, initial walkdowns of accessible areas in support of initial license renewal commitment for accessible areas was completed.

   The walkdowns of the Unit 1 and Unit 2 Containments were completed in 2017 and 2018, respectively.

Discrepancies identified during the walkdown were entered into the Corrective Action Program as discussed below:

- Two cables in a cable tray in the Unit 1 Auxiliary Building appeared to have a slight abnormality on a one-inch section of the cable jacket. An evaluation concluded that the abnormality was limited to only these two cables, no similar conditions were found in comparable locations in the Unit 2 Auxiliary Building, there were no signs of an adverse environment, and the cables could perform their intended function.
- A conduit in the Unit 1 Auxiliary Building was observed to be disconnected and hanging loose. There were no concerns about the functionality of the cable inside the conduit. A work order was initiated and the conduit was repaired.
- Two conduits located in the Unit 2 Main Steam Valve House appeared to have a slightly discolored section of about twelve inches due to heat. The conduits were in close proximity to a Non Return Valve (NRV). A follow-on inspection concluded that there was no heating or other degradation of the cable jacket.
- During the walkdown in the Unit 2 Containment, rust was identified on a junction box. Inspection of the cables internal to the junction box found them to be in satisfactory condition, and the rust was considered to be minor.
- A loose conduit seal was identified in a cable tray during the walkdown of the Unit 1 Containment. An Engineering evaluation concluded that the loose seal did not impact the functionality of the cable internal to the conduit. A work order was initiated and the seal was repaired.

2. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion was reached that no performance deficiencies or learning opportunities were identified for the Non-EQ Cable Monitoring AMA (UFSAR Section 18.1.4) related to the visual inspection of Non-EQ cables and connections.
3. In May 2016, electrical maintenance inspected the Unit 2 polar crane. A deteriorated trolley festoon cable with some conductors showing through the insulation was observed. Most of the cracking was where the cable was hung on the saddle hangers.

   Engineering supported the electrical maintenance finding by performing a visual inspection of the control/power cables of the Unit 2 polar crane. The festoon cable was found to have multiple spots of brittle cracking, including insulation and conductor exposure. The cracking appeared to be due to long term aging degradation, and most of the cracking was found at the bracket (saddle) supports along the length of the crane. Electrical maintenance repaired the cable insulation and jacket in accordance with approved specifications (taping the degraded cable jackets). The Unit 2 polar crane was determined to be able to perform its intended function.

4. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.
5. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the Non-EQ Cable Monitoring AMA (UFSAR Section 18.1.4) related to the visual inspection of Non-EQ cables and connections.
6. In April 2019, an effectiveness review was performed on the Non-EQ Cable Monitoring AMA (UFSAR Section 18.1.4), that included a visual inspection of a limited, but representative sample of accessible cable jackets and connector coverings among its inspection activities. The AMA was evaluated against the performance criteria identified in NEI 14-12, "Aging Management Program Effectiveness." No gaps were identified by the effectiveness review related to the visual inspection of Non-EQ cables and connections.

The above examples of operating experience provide objective evidence that the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program includes activities to perform visual inspections to identify the aging effect of reduced electrical resistance for accessible electrical cables and connections insulation material subjected to an adverse localized environment within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.38 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits

Program Description

The *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program is an existing performance monitoring program that manages the aging effects of reduced electrical insulation resistance of the electrical cables and connections (cable system) insulation material used in instrumentation circuits with sensitive, high-voltage, low-level current signals that are subjected to adverse localized environments caused by temperature, radiation, or moisture.

Exposure of electrical cables to adverse localized environments can result in reduced insulation resistance. Reduced insulation resistance causes an increase in leakage currents between conductors and from individual conductors to ground. A reduction in insulation resistance is a concern for circuits with sensitive, high voltage, low-level current signals because a reduced insulation resistance may contribute to signal inaccuracies.

The program applies to the Containment high range radiation monitor system, the post-accident neutron monitoring system, and the excore neutron monitoring system.

The Containment high range radiation monitor system cables are connected during calibration. Therefore, the calibration results or findings of surveillance testing programs are evaluated to identify the existence of electrical cable and connection insulation material aging degradation. The reviews of the calibration results will be completed prior to the subsequent period of extended operation and at least every ten years thereafter.

The excore neutron monitoring system cables are disconnected during calibration. The program performs a proven cable test for detecting deterioration of the cable system insulation material. The test frequency is based on Engineering evaluation and is performed at least once every ten years.

The post-accident neutron monitoring system electrical cables are disconnected during calibration. The program will perform a proven cable test for detecting deterioration of the cable system insulation material. The tests will be completed prior to the subsequent period of extended operation and at least every ten years thereafter.

NUREG-2191 Consistency

The *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program is an existing program that, following enhancement, will be consistent, with 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.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Scope of Program (Element 1)

1. A new procedure will be developed to add testing of the post-accident neutron monitoring system cables and connections external to Containment to the Program. The procedure will evaluate reduced electrical insulation resistance by measuring cable resistance and capacitance.

Acceptance Criteria (Element 6)

2. The Nuclear Instrumentation test procedures will be enhanced to specify the acceptance criteria.

Corrective Actions (Element 7)

3. Procedures will be enhanced to include corrective actions and a requirement for performance of an Engineering evaluation when cable system test results do not meet the acceptance criteria. Results of the Engineering evaluation will determine if the test frequency needs to be increased.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In May 2009, baseline insulation resistance tests and time domain reflectometry tests were performed for a newly installed Unit 2 High Range Radiation Monitoring detector. The vendor recommended these tests to obtain baseline data. The tests were completed with satisfactory results.

2. In September 2011, it was recommended that insulation resistance tests and time domain reflectometry testing or some other adequate form of the power range detector evaluations be performed on the Unit 1 detectors in order to ensure their state of health prior to required operation. Insulation resistance tests and time domain reflectometry testing was performed on all Unit 1 power range channels with satisfactory results.

3. In October 2012, a lower than expected resistance reading was obtained on a Unit 2 power range detector cable. The readings were for the inner shield to outer shield for the high voltage, upper detector and lower detector cables. The vendor concluded that a short between the inner and outer shield will not impact the operability of the power range channel. Engineering concluded that there were no long term reliability concerns with the continued operation of the power range detector.
4. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion was reached that no performance deficiencies or learning opportunities were identified for the Non-EQ Cable Monitoring AMA (UFSAR Section 18.1.4) related to the inspection and testing of the sensitive, high-voltage, low-signal in-scope nuclear instrumentation (NI) source range, intermediate range and power range cables.
5. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.
6. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the Non-EQ Cable Monitoring AMA (UFSAR Section 18.1.4) related to the inspection and testing of the sensitive, high-voltage, low-signal in-scope nuclear instrumentation (NI) source range, intermediate range and power range cables.

    A review of the documentation associated with the testing of the Non-EQ cables used in instrumentation circuits did not reveal any age-related degradation.

7. In April 2019, an effectiveness review was performed on the Non-EQ Cable Monitoring AMA (UFSAR Section 18.1.4), that included inspection and testing of the sensitive, high-voltage, low-signal in-scope nuclear instrumentation (NI) source range, intermediate range and power range cables. The AMA was evaluated against the performance criteria identified in NEI 14-12, "Aging Management Program Effectiveness." No gaps were identified by the effectiveness review related to the inspection and testing of the sensitive, high-voltage, low-signal in-scope nuclear instrumentation source range, intermediate range and power range cables.

The above examples of operating experience provide objective evidence that the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program includes activities to perform testing to identify the aging effect of reduced electrical insulation resistance for electrical cable and connection (cable system) electrical insulation material subject to sensitive, high-voltage, low-level current signals that are subjected to adverse localized environments caused by temperature, radiation, or moisture within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.39 Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is an existing condition monitoring program that manages the aging effect of reduced electrical insulation resistance or degraded dielectric strength of inaccessible medium-voltage cables (operating voltages of 2kV to 35kV) exposed to significant moisture.

The program applies to inaccessible or underground non-EQ medium-voltage power cable installations (e.g., installed in buried conduits, duct banks, underground vaults, manholes, cable trenches or direct buried installations), within the scope of subsequent license renewal 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. Power cable exposure to significant moisture may cause reduced electrical insulation resistance or degraded dielectric strength that can potentially lead to failure of the cable's insulation system.

Periodic actions are taken to prevent non-EQ inaccessible medium-voltage power cables from being exposed to significant moisture. Accessible cable conduit ends and manhole/vaults associated with cables included in this program are inspected for water collection and the water is drained, as necessary. Manholes associated with in-scope non-EQ inaccessible medium-voltage power cables are inspected to confirm that cables are not wetted or submerged in water, cables/vaults and cable support structures are intact and dewatering/drainage systems (i.e., sump pumps) and associated alarms operate properly. This inspection and water removal is performed based on actual plant experience over time with an inspection frequency being at least annually and after event driven occurrences (such as heavy rain, rapid thawing of ice and snow, or flooding). Dewatering devices and associated alarms are inspected and their operation verified periodically. Manholes associated with in-scope non-EQ inaccessible medium-voltage power cables are not equipped with automatic water level monitoring and alarm systems.

In-scope non-EQ inaccessible medium-voltage power cables routed through manholes, and duct banks are tested to detect reduced electrical insulation resistance or degraded dielectric strength of the cable's insulation system. Testing that is appropriate to the application at the time of the testing is performed. Cable testing includes one or more proven testing methods (such as dielectric loss [dissipation factor (Tan-Delta)/power factor], AC voltage withstand, partial discharge, step voltage, time domain reflectometry, insulation resistance and polarization index, or line resonance analysis).

Cable testing acceptance criteria are defined prior to each test. Cables are tested at least once every six years. More frequent testing may occur based on test results and operating experience.

A plant-specific inaccessible medium-voltage cable test matrix that documents inspection methods, test methods, and acceptance criteria for the in-scope inaccessible medium-voltage power cables will be developed based on OE.

There are no submarine cables or other cables designed for continuous wetting or submergence currently in the scope of this program. Future installed cables of this design would be considered for inclusion in this program.

NUREG-2191 Consistency

The *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is an existing program that, following enhancement, will be consistent, with NUREG-2191, Section XI.E3A, Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements as modified by SLR-ISG-Electrical-2020-XX, Updated Aging Management Criteria for Electrical Portions of the Subsequent License Renewal Guidance.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Preventive Actions (Element 2)

1. Procedures will be revised to inspect and dewater, if required, the in-scope manholes after event driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding.
2. Procedures will be revised to add a step stating that automatic or passive drainage features of manholes are operating properly.
3. Procedures will be revised to add a step that includes a requirement for testing medium-voltage cables that are exposed to significant moisture to determine the condition of the electrical insulation.

Preventive Actions (Element 2), Parameters Monitored/Inspected (Element 3), Detection of Aging Effects (Element 4), and Acceptance Criteria (Element 6)

4. Procedures will be revised to add cables from RSST `B' and `C' to Bus 1G and Bus 2G, and associated handholes, to the scope of the program and perform inspections, dewatering, and testing with the first inspection scheduled prior to the subsequent period of extended operation.

Parameters Monitored/Inspected (Element 3)

5. Procedures will be revised to add a step to evaluate adjusting the inspection frequency of manholes based on plant-specific operating experience over time with water collection.

Detection of Aging Effects (Element 4) and Acceptance Criteria (Element 6)

6. A plant-specific inaccessible medium-voltage cable test matrix will be created that documents inspection methods, test methods, and acceptance criteria for the in-scope inaccessible medium-voltage power cables based on OE. Testing will be conducted at least every six years.

Monitoring and Trending (Element 5)

7. Procedures will be revised to include a requirement to review visual inspection and physical test results that are trendable and repeatable to provide additional information on the rate of cable or connection insulation degradation.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program, has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In December 2011, during inspection of manholes in the switchyard that contain medium-voltage cables, an in-scope manhole was found with water high enough to submerge the low point of the lowest layer of the cables. The water was pumped down. These cables were installed in 2007 and have tree retardant XLPE insulation that is designed to resist the formation of water trees.

   This manhole was last inspected in 2010 and water levels were below the cables. The short-term submergence of a portion these cables does not affect their ability to perform their intended function. This is due to the tree retardant design. The base line tan delta tests were performed in October of 2011. The test results were acceptable and the cables were given a six-year test frequency.

2. In July 2013, during inspection of cable vaults in the switchyard that contain 34.5kV cables, an in-scope manhole was found with 18 inches of water. The cables were installed high on the side walls and were not submerged by the water level. The cable vault was pumped in accordance with existing procedures.

3. In May 2016, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase I inspection to be conducted during the Fall 2016 Unit 1 refueling outage. The conclusion was reached that no performance deficiencies or learning opportunities were identified for the Non-EQ Cable Monitoring AMA (UFSAR Section 18.1.4) related to the visual inspection of in-scope manholes for water collection and cable submergence and testing of submerged cables as required by an Engineering evaluation.
4. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.
5. In May 2017, an assessment was performed to determine the progress and substance of license renewal commitment closure and readiness for the IP 71003 NRC Phase II inspection to be conducted for Units 1 and 2 from November through December of 2017. The conclusion was reached that no areas for improvement or enhancements were identified for the Non-EQ Cable Monitoring AMA (UFSAR Section 18.1.4) related to the visual inspection of in-scope manholes for water collection and cable submergence and testing of submerged cables as required by an Engineering evaluation.
6. In November 2017, engineering inspections were performed for an in-scope manhole. The as-found water level was high enough to wet the bottom cable tray in the vault and submerge the cables. The cable vault does contain safety-related low-voltage and medium-voltage cables. No indications of cable degradation were identified based on an Engineering evaluation, and the cables were able to continue performing their design function.
7. In April 2019, an effectiveness review was performed on the Non-EQ Cable Monitoring AMA, (UFSAR Section 18.1.4), that included a periodic inspection of manholes containing medium-voltage cables that are within the scope of license renewal for water intrusion and cable submergence among its inspection activities. The AMA was evaluated against the performance criteria identified in NEI 14-12, “Aging Management Program Effectiveness.” No gaps were identified by the effectiveness review related to periodic manhole inspections.

However, further review determined that gaps were identified by the effectiveness review related to the manhole inspections. Specifically, the in-scope manholes containing medium-voltage cables that are within the scope of license renewal had not been inspected since 2016. A Condition Report was initiated to address the concern that allowed this event to occur. Subsequently, the manholes containing the in-scope medium-voltage cables were inspected in November 2019 and were found to have minimal or no water accumulation and no cables were observed to be submerged.

The above examples of operating experience provide objective evidence that the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program includes activities to perform testing and visual inspections of manholes to identify the aging effect of reduced electrical insulation resistance or degraded dielectric strength for non-EQ inaccessible medium-voltage cables (operating voltage of 2kV to 35kV) exposed to significant moisture within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.40 Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The *Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new condition monitoring program that will manage the aging effect of reduced electrical insulation resistance or degraded dielectric strength leading to electrical failure of in-scope non-EQ inaccessible instrument and control (I&C) cables. This program will apply to inaccessible or underground (e.g., installed in buried conduit, cable trenches, cable troughs, duct banks, underground vaults, manholes, or direct buried) non-EQ instrument and control cable, within the scope of subsequent license renewal that are exposed to significant moisture, including cables designed for continuous wetting or submergence. 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. I&C cable exposure to significant moisture may cause reduced electrical insulation resistance or degraded dielectric strength that can potentially lead to failure of the cable's insulation system. Cable wetting or submergence resulting from event driven occurrences and mitigated by either automatic or passive drains is not considered significant moisture.

Periodic actions will be taken to prevent inaccessible I&C cables from being exposed to significant moisture. Accessible cable conduit ends and manholes/vaults associated with the cables included in this program will be inspected for water collection and the water is drained, as necessary. Manholes associated with in-scope non-EQ inaccessible I&C cables will be inspected to confirm that cables are not wetted or submerged in water, cables/splices and cable support structures are intact, and dewatering/drainage systems (i.e., sump pumps) and associated alarms operate properly. This inspection and water removal will be performed based on actual plant experience over time with inspection frequency being at least annually and after event driven occurrences (such as heavy rain, rapid thawing of ice and snow, or flooding). Dewatering devices and associated alarms will be inspected and their operation verified periodically. Manholes associated with in-scope non-EQ inaccessible I&C cables are not equipped with automatic water level monitoring and alarm systems.

In-scope, non-EQ, inaccessible I&C cables routed through manholes, pits, and duct banks that are exposed to significant moisture will be evaluated to determine if testing is required. If required, initial testing will be performed on a sample population to determine the condition of the electrical insulation. One or more tests may be required due to the cable type, application, and electrical insulation to determine degradation of the electrical insulation. A one-time test prior to the subsequent period of extended operation will be performed for cable exposed to significant moisture if the cable insulation type is known to degrade with continuous exposure to moisture or if operating experience indicates insulation degradation resulting from continuous exposure to moisture. Tests may include combinations of in situ or laboratory, electrical, physical, or chemical tests. The need for additional periodic tests and inspections will be determined by the test results and/or inspection results, as well as industry and plant specific operating experience.

Testing of installed in-service inaccessible and 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 or low-voltage cable subject to the same or bounding service environment, in-service application, cable routing, construction, manufacturing and insulation material may be credited in lieu of or in combination with testing of installed in-service inaccessible I&C cable when testing is recommended. A sampling methodology will be used to evaluate a large number of I&C cables exposed to a significant moisture event.

NUREG-2191 Consistency

The *Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new program that, when implemented, will be consistent, with NUREG-2191, Section XI.E3B, Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements as modified by SLR-ISG-Electrical-2020-XX, Updated Aging Management Criteria for Electrical Portions of the Subsequent License Renewal Guidance.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 2011, a review identified that open work orders existed to seal duct banks in manholes and structures that would prevent flooding paths into safety-related areas. These work orders had been created in 2006, but had not been completed and needed to have a higher priority. The implementation schedule was re-evaluated for these work orders and they were completed by July of 2011.

2. In March 2012, during the annual performance of cable vault pumping and inspections water level inside a Unit 1 safety-related license renewal manhole was identified to be sufficient to partially submerge safety-related cables in the lower half of a pull box internal to the manhole. Water level in the manhole was pumped down, the manhole was inspected and no adverse issues were identified. A sump pump has subsequently been installed in this manhole to prevent water accumulation.
3. In May 2015, during periodic manhole inspections a nonsafety-related cable vault was identified to have sufficient water to partially submerge cables. Water in the manhole was pumped down and the manhole was inspected with no adverse issues identified since the last inspection. A sump pump was subsequently installed in this manhole to prevent water accumulation.
4. In June 2016, during performance of the semi-annual pumping and inspection of electrical vaults, a hand hole was identified with sufficient water to submerge several cables. The water was pumped down and engineering inspected the hand hole with no adverse issues identified.
5. In October 2019, during inspection of a Unit 1 license renewal manhole, water was found to have collected sufficiently to submerge the lowest cable tray containing safety-related low voltage power cables. A pull box cover was also found to be damaged from water exposure. The cables were evaluated by engineering as being capable of performing their intended function. Water was pumped out of the manhole, and work orders were initiated to retest the cable and repair the pull box.

The above examples of operating experience provide objective evidence that the *Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will include activities to perform visual inspections to identify significant moisture and submergence to manage the aging effect of reduced electrical insulation resistance or degraded dielectric strength for non-EQ inaccessible I&C cables within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will be evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements will be provided for locations where aging effects are found. The program will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the implementation of the *Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will effectively manage aging prior to a loss of intended function. Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The implementation of the *Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.41 Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The *Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new condition monitoring program that will manage the aging effect of reduced electrical insulation resistance or degraded dielectric strength of inaccessible low-voltage power (operating voltage less than 2kV) cables exposed to significant moisture. This program will apply to inaccessible or underground (e.g., installed in buried conduit, cable trenches, cable troughs, duct banks, underground vaults, or direct buried) low-voltage power cables, within the scope of subsequent license renewal that are exposed to significant moisture, including cables designed for continuous wetting or submergence. 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. Low-voltage power cable exposure to significant moisture may cause reduced electrical insulation resistance or degraded dielectric strength that can potentially lead to failure of the cable's insulation system. Cable wetting or submergence resulting from event driven occurrences and mitigated by either automatic or passive drains is not considered significant moisture.

Periodic actions will be taken to prevent inaccessible low-voltage power cables from being exposed to significant moisture. Accessible cable conduit ends and manholes/vaults associated with the cables included in this program will be inspected for water collection and the water is drained, as necessary. Manholes associated with in-scope non-EQ inaccessible low-voltage power cables will be inspected to confirm that cables are not wetted or submerged in water, cables/splices and cable support structures are intact, and dewatering/drainage systems (i.e., sump pumps) and associated alarms operate properly. This inspection and water removal will be performed based on actual plant experience over time with inspection frequency being at least annually and after event driven occurrences (such as heavy rain, rapid thawing of ice and snow, or flooding). Dewatering devices and associated alarms will be inspected and their operation verified periodically. Manholes associated with in-scope non-EQ inaccessible low-voltage power cables are not equipped with automatic water level monitoring and alarm systems.

In-scope, non-EQ, inaccessible low-voltage power cables routed through manholes, pits, and duct banks that are exposed to significant moisture will be evaluated to determine if testing is required. If required, initial testing will be performed on a sample population to determine the condition of the electrical insulation. One or more tests may be required due to the cable type, application, and electrical insulation to determine degradation of the electrical insulation. A one-time test prior to the subsequent period of extended operation will be performed for cable exposed to significant moisture if the cable insulation type is known to degrade with continuous exposure to moisture or if operating experience points to insulation degradation resulting from continuous exposure to moisture. Tests may include combinations of in situ or laboratory, electrical, physical, or chemical tests. The need for additional periodic tests and inspections will be determined by the test results and/or inspection results, as well as industry and plant specific operating experience.

Testing of installed in-service inaccessible and underground low-voltage power cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible medium-voltage or instrument and control cable subject to the same or bounding service environment, in-service application, cable routing, construction, 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 recommended. A sampling methodology will be used to evaluate a large number of low-voltage power cables exposed to a significant moisture event.

NUREG-2191 Consistency

The *Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new program that, when implemented, will be consistent, with NUREG-2191, Section XI.E3C, Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements as modified by SLR-ISG-Electrical-2020-XX, Updated Aging Management Criteria for Electrical Portions of the Subsequent License Renewal Guidance.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 2011, a review identified that open work orders existed to seal duct banks in manholes and structures that would prevent flooding paths into safety-related areas. These work orders had been created in 2006, but had not been completed and needed to have a higher priority. The implementation schedule was re-evaluated for these work orders and they were completed by July of 2011.
2. In March 2012, during the annual performance of cable vault pumping and inspections water level inside a Unit 1 safety-related license renewal manhole was identified to be sufficient to partially submerge safety-related cables in the lower half of a pull box internal to the manhole.

Water level in the manhole was pumped down, the manhole was inspected and no adverse issues were identified from the inspection. A sump pump has subsequently been installed in this manhole to prevent water accumulation.

3. In May 2015, during periodic manhole inspections a nonsafety-related cable vault was discovered to have sufficient water to partially submerge cables. Water in the manhole was pumped down and the manhole was inspected with no adverse issues identified since the last inspection. A sump pump was subsequently installed in this manhole to prevent water accumulation.
4. In June 2016, during performance of the semi-annual pumping and inspection of electrical vaults, a hand hole was identified with sufficient water to submerge several cables. The water was pumped down and engineering inspected the hand hole with no adverse issues identified.
5. In October 2019, during inspection of a Unit 1 license renewal manhole, water was found to have collected sufficiently to submerge the lowest cable tray containing safety-related low voltage power cables. A pull box cover was also found to be damaged from water exposure. The cables were evaluated by engineering as being capable of performing their intended function. Water was pumped out of the manhole, and work orders were initiated to retest the cable and repair the pull box.

The above examples of operating experience provide objective evidence that the *Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will include activities to perform visual inspections to identify significant moisture and submergence to manage the aging effect of reduced electrical insulation resistance or degraded dielectric strength for non-EQ inaccessible low-voltage power cables within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will be evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements will be provided for locations where aging effects are found. The program will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the implementation of the *Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will effectively manage aging prior to a loss of intended function. Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The implementation of the *Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.42 Metal-Enclosed Bus

Program Description

The *Metal Enclosed Bus* program is an existing condition monitoring program that manages the aging effects of increased electrical resistance of metal enclosed bus (MEB) electrical connections; reduced electrical insulation resistance of MEB electrical insulation and insulators; surface cracking, crazing, scuffing, dimensional change (e.g., “ballooning” and “necking”), shrinkage, discoloration, hardening, and loss of strength of MEB enclosure assembly elastomers; and loss of material of the external surface of MEB enclosure assemblies. Bus enclosure assemblies (internal and external), bus bar insulation, bus bar insulating supports, and bus bar bolted connections are included in the scope of the program.

The internal portions of the accessible bus enclosure assemblies are visually inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The accessible bus insulation is visually inspected for signs of reduced electrical insulation resistance, such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination which may indicate overheating or aging degradation. The accessible internal bus insulating supports are visually inspected for structural integrity and signs of cracks. Accessible external metallic surfaces are visually inspected for unacceptable loss of material due to general, pitting, and crevice corrosion. Accessible enclosure assembly elastomers, including gaskets, boots, and sealants, are visually inspected for degradation, including surface cracking, crazing, scuffing, dimensional change (e.g., “ballooning” and “necking”), shrinkage, discoloration, hardening and loss of strength. A sample of accessible bolted connections is inspected for increased electrical resistance of connection by measuring connection resistance using a micro-ohmmeter.

Metal enclosed buses are to be free from unacceptable visual indications of surface anomalies which suggest degradation exists. Additionally, unacceptable indications of external or internal material condition or contamination should not be present. An unacceptable indication is defined as a noted condition that, if left unmanaged, could lead to a loss of intended function. External surfaces are to be free from general, pitting and crevice corrosion that results in an unacceptable loss of material. Enclosure assembly elastomers are to be free from unacceptable visual indications of degradation. The bolted connections inspected by resistance measurements will be confirmed to be within the acceptance criteria established in program implementing procedures. Unacceptable results are subject to evaluation under the Corrective Action Program.

The first inspection, including measuring connection resistance, will be completed prior to the subsequent period of extended operation and at least every 10 years thereafter.

NUREG-2191 Consistency

The *Metal Enclosed Bus* program is an existing program that, following enhancement, will be consistent, with NUREG-2191, Section XI.E4, Metal Enclosed Bus.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Scope of Program (Element 1) and Detection of Aging Effects (Element 4)

1. A new procedure will be created to add the MEB connecting ‘A’ Reserve Station Service Transformer to Bus 1G and Bus 2G to the scope of the program and perform inspections and testing on a ten year frequency with the first inspection scheduled prior to the subsequent period of extended operation.

Parameters Monitored/Inspected (Element 3)

2. Procedures will be revised to add a step for inaccessible sections of bus duct that requires engineering to provide guidance for performance of electrical testing of connections using an ohmmeter and for performance of visual inspection of the bus duct using a borescope.
3. Inspection procedures will be revised to add a note stating that 20% of the accessible bolted connection population, with a maximum of 25, is a representative sample for increased resistance of connection inspections.

Monitoring and Trending (Element 5)

4. Procedures will be revised to require the transmittal of bus connection resistance values to engineering for trending to provide information on the rate of connection degradation.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Metal Enclosed Bus* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In November 2009, in response to an industry event identifying maintenance practices as the likely cause for catastrophic failure of bus duct and automatic shutdown of a nuclear unit, existing procedures were verified to include requirements for periodic inspection of switchgear bus connection hardware for tightness and degradation. Also, procedures were verified to require review and approval by engineering and maintenance management for deferral of preventive maintenance activities.

2. In October 2014, evaluation of an industry operating experience event describing electrical faults resulting from failure of a non-segregated phase bus duct was performed to identify gaps in procedures and preventive maintenance activities. As a result, new procedures and associated recurring events for periodic maintenance were created to address periodic cleaning and inspection of non-segregated phase bus ducts. Bus inspections have been performed on bus duct associated with the 'D' transfer bus, the 'F' transfer bus, emergency bus '1H,' emergency bus '2H,' and emergency bus '2J' with one anomaly identified. Cracked boots found on the 'D' transfer bus MEB were replaced during the inspection.

The above examples of operating experience provide objective evidence that the *Metal Enclosed Bus* program includes activities to perform visual inspections and electrical testing to identify reduced electrical insulation resistance, cracking, and loss of continuity or increased contact resistance for metal enclosed bus within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Metal Enclosed Bus* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Metal Enclosed Bus* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Metal Enclosed Bus* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.43 Fuse Holders

Program Description

The *Fuse Holders* program is an existing condition monitoring program that manages increased electrical resistance of connection of the metallic clamps and reduced electrical insulation resistance of the fuse holder electrical insulation material.

The Fuse Holders program was developed specifically to address aging management of fuse holder insulation material and fuse holder metallic clamp aging mechanisms and effects. The Fuse Holders program utilizes visual inspection and testing to identify age-related degradation for both fuse holder electrical insulation material and fuse holder metallic clamps. Visual inspection and testing provide reasonable assurance that the applicable aging effects are identified, and fuse holder insulators and metallic clamps are managed.

Fuse holders are typically constructed of blocks of rigid insulating material such as phenolic resins. Metallic clamps are attached to the blocks to hold each end of the fuse. The clamps, which are typically made of copper, can be spring-loaded clips or bolt lugs to which the fuse ends are connected. Industry operating experience has shown that repetitive removal and reinsertion of fuses during maintenance or surveillance activities can lead to degradation of the fuse holders. Fuse holders located outside of active equipment, where fuses are removed and replaced frequently for maintenance or surveillance activities are also included within this program to manage these repetitive activities.

The metallic portion of fuse holders that are within the scope of subsequent license renewal and subject to aging management are tested for the following aging stressors: increased resistance of connection due to chemical contamination, corrosion, and oxidation or fatigue caused by ohmic heating, thermal cycling, electrical transients, frequent removal and insertion, or vibration. Thermography is used to test the metallic portion of fuse holders for increased resistance of the connection.

Fuse holders within the scope of subsequent license renewal, and subject to aging management, are visually inspected to provide an indication of the condition of the electrical insulation portion of the fuse holders. Fuse holders are visually inspected for electrical insulation surface anomalies indicating signs of reduced electrical insulation resistance due to thermal/thermoxidative degradation of organics, radiolysis and photolysis [ultraviolet sensitive materials only] of organics, radiation-induced oxidation, and moisture intrusion as indicated by signs of embrittlement, discoloration, cracking, melting, swelling, or surface contamination.

The first visual inspections and testing will be performed prior to the subsequent period of extended operation and at least once every 10 years thereafter.

NUREG-2191 Consistency

The *Fuse Holders* program is an existing program that is consistent with NUREG-2191, Section XI.E5, Fuse Holders.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Fuse Holders* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 2010, during performance of thermography in a pressurizer heater fuse panel, elevated temperatures were noted on connection points on a fuse block. The block was replaced and tested satisfactorily.
2. In April 2018, during performance of thermography on pressurizer heater fuse blocks, a single fuse in fuse holder was measured with a temperature 45 degrees hotter than other similar connections. The fuse holder was replaced and tested satisfactorily.
3. In February 2020, during a comprehensive review of fuses and fuse holders for the subsequent license renewal Fuse Holders program, it was identified that 52 fuse holders associated with the pressurizer heater fuses met the requirements for inclusion into the program. These fuse holders had not been previously identified following issuance of regulatory guidance for fuse holders as required by an initial License Renewal commitment.

   Fuse holders associated with the pressurizer heaters are visually inspected and tested each refueling cycle to identify and correct indications of degradation that may prevent operation of the heaters. A review of operating experience for fuse holder inspections from 2008 did not identify any loss of intended function.

   The station was notified and this condition was entered into the Corrective Action Program to revise the UFSAR and affected aging management documents associated with initial license renewal.

The above examples of operating experience provide objective evidence that the *Fuse Holders* program includes activities to perform visual inspection and testing to identify increased electrical resistance of connection of the metallic clamps and reduced electrical insulation resistance of the fuse holder electrical insulation material for fuse holders within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Fuse Holders* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Fuse Holders* program will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Fuse Holders* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.44 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The *Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new condition monitoring program that will manage the aging effect of increased electrical resistance of the electrical cable connections (metallic parts).

This program will perform a one-time inspection, on a representative sampling basis, to confirm the absence of loosening of connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion and oxidation. The following factors will be considered for sampling: application (medium and low voltage), circuit loading (high load), connection type, and location (high temperature, high humidity, vibration, etc.).

Non-EQ electrical cable connections (metallic parts) associated with cables within the scope of subsequent license renewal will be tested prior to the subsequent period of extended operation to provide an indication of the integrity of the cable connections. The specific type of test to be performed will be determined based on the type of connection and will be a proven method for detecting loose connections, such as thermography, contact resistance testing, or other appropriate testing methods without removing the connection insulation such as heat shrink tape, sleeving, insulating boots, etc.

Twenty percent of a connector type population with a maximum sample of 25 constitutes a representative connector sample size. Otherwise a technical justification of the methodology and sample size used for selecting components under test will be included as part of the program's documentation.

A representative sample of cable connections within the scope of subsequent license renewal will be tested on a one-time test basis or at least once every five years if only visual inspection is used to provide an indication of the integrity of the cable connections. Depending on the findings of the one-time test, subsequent testing may have to be performed within ten years of initial testing. The first visual inspections or tests for subsequent license renewal are to be completed prior to the subsequent period of extended operation. As an alternative to testing for accessible cable connections that are covered with heat shrink tape, sleeving, insulating boots, etc., a visual inspection of insulation materials to detect surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling or surface contamination may be implemented. When this alternative visual inspection is used to check cable connections, the first inspection will be completed prior to the subsequent period of extended operation and repeated at least every five years, thereafter. The basis for performing only the alternative visual inspection to monitor age-related degradation of cable connections will be documented.

NUREG-2191 Consistency

The *Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is a new program that, when implemented, will be consistent, with NUREG-2191, Section XI.E6, Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following example of operating experience provides objective evidence that the *Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In August 2019, a search for plant-specific OE related to loose connections from November 2008 to January 2019 was performed. Although cases of loosening of connections were identified during testing and maintenance activities, there were no conclusive examples that the loosening of connections was due to the aging mechanisms of thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion and oxidation.

The above example of operating experience provides objective evidence that the *Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will include activities to perform testing and visual inspections to identify increased electrical resistance for electrical cable connections (metallic parts) within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will be evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements will be provided for locations where aging effects are found. The program will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the implementation of the *Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will effectively manage aging prior to a loss of intended function. Industry and plant specific operating experience will be evaluated in the development of this program.

Conclusion

The implementation of the *Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.45 High-Voltage Insulators

Program Description

The *High-Voltage Insulators* program is a new condition monitoring program that will manage loss of material and reduced electrical insulation resistance for insulators that are credited for recovery of offsite power. Insulators in the scope of this program operate at 34.5 kV and 4,160V and include porcelain, toughened glass, and polymer materials.

Insulator surfaces of porcelain, toughened glass, and polymer insulators will be visually inspected to detect reduced electrical insulation resistance aging effects including cracks, missing sheds, foreign debris, excessive salt, dust, fog, cooling tower plume, industrial effluent contamination, and loss of material from impact of wind driven particles. Additionally, polymer insulator surfaces will be visually inspected to detect signs of polymer degradation, swelling, discoloration, chalking, crazing, mechanical failure of components, and swelling or peeling of silicone rubber sleeves. Metallic parts of the insulator will be visually inspected to detect loss of material due to mechanical wear and corrosion.

Insulators within the scope of the High-Voltage Insulators program will be visually inspected at least once every two years initially with the frequency adjusted based on plant specific operating experience with the specific type of insulator. For insulators that are coated, the visual inspection will be performed at least once every five years.

The first inspections for the subsequent period of extended operation will be completed prior to the subsequent period of extended operation.

NUREG-2191 Consistency

The *High-Voltage Insulators* program is a new program that, when implemented, will be consistent, with NUREG-2191, Section XI.E7, High-Voltage Insulators as modified by SLR-ISG-Electrical-2020-XX, Updated Aging Management Criteria for Electrical Portions of the Subsequent License Renewal Guidance.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *High-Voltage Insulators* program will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. Plant-specific operating experience was reviewed to ensure that the aging effects discussed in NUREG-2191, Section XI, XI.E7 aging management program are bounding (i.e., that there are no relevant plant-specific aging effects in addition to that described in NUREG-2191). The Corrective Action Program was searched to determine if aging degradation has been identified for in-scope high-voltage insulators. No occurrences of loss of insulation resistance or loss of material that resulted in a loss of intended function were observed.
2. In January 1989, an industry event identified a reactor shutdown due to flashover of a 500 kV insulator. The buildup of contamination (mineral deposits from cooling tower spray) was not removed by natural means (insufficient season rainfall) or by manual cleaning. A wind driven cooling tower plume engulfed the affected transformers and caused the flashover. The North Anna site includes a forced draft Bearing Cooling tower located within 600 feet of the RSSTs and overhead tubular bus where in-scope insulators are used. Contamination of insulators due to drift from the Bearing Cooling tower has not historically been identified as a problem, and seasonal rainfall is sufficient to wash airborne contaminants off of the insulators. The environment at North Anna is not as arid and does not as readily promote deposition of contaminants on porcelain, toughened glass, or polymer insulators. No flashover events for in-scope insulators have been identified at North Anna.
3. In October 2012, an industry event identified a reactor shutdown following a flashover on a 500 kV capacitive coupled voltage transformer (CCVT) insulator. The heavy level of contamination from the salt spray environment was not properly considered during design of the CCVT that flashed over. Dominion Energy Electric Transmission follows IEEE C29.9 for minimum leakage distance for insulators in each voltage class. Also, Electric Transmission uses high creep porcelain for all CCVTs in the system as a practice to prevent confusion over applications. Insulators at North Anna have not experienced significant contamination and seasonal rainfall is sufficient to minimize accumulation of contamination. No flashover events for in-scope insulators have been identified.

The above examples of operating experience provide objective evidence that the *High-Voltage Insulators* program will include activities to perform visual inspections to identify loss of material and reduced electrical insulation resistance for high-voltage insulators within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *High-Voltage Insulators* program will be evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements will be provided for locations where aging effects are found. The program will be informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the implementation of the *High-Voltage Insulators* program will effectively manage aging prior to a loss of intended function. Industry and plant specific operating experience will be evaluated in the development and implementation of this program.

Conclusion

The implementation of the *High-Voltage Insulators* program will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B3 TLAA Support Activities

B3.1 Fatigue Monitoring

Program Description

The *Fatigue Monitoring* program is an existing preventive program that manages cycle-based fatigue or other types of cyclic loading of the mechanical or structural components with a fatigue time-limited aging analysis (TLAA) or other analysis that depends on the number of occurrences and severity of transient cycles.

The program provides an acceptable basis for managing structures and components (SCs) that are the subject of fatigue or cycle-based time-limited aging analyses (TLAAs) or other analyses that assess fatigue or cyclical loading, consistent with the requirements in 10 CFR 54.21(c)(1)(iii). Examples of cycle-based fatigue analyses for which the *Fatigue Monitoring* program may be used include, but are not limited to:

(a) cumulative usage factor (CUF) analyses or their equivalent (e.g., I_c-based fatigue analyses, as defined in specific design codes) that are performed in accordance with United States of America Standards (USAS) for Class 1 nuclear power piping and American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) requirements for specific mechanical or structural components.

(b) fatigue analysis calculations for assessing the effects of the reactor water environment, known as environmentally assisted fatigue (EAF);

(c) fatigue flaw growth analyses that are based on cyclical loading assumptions;

(d) fracture mechanics analyses that are based on cycle-based loading assumptions; and

(e) fatigue waiver or exemption analyses that are based on cycle-based loading assumptions.

Fatigue of components is managed by monitoring one or more relevant fatigue parameters, which include, but are not limited to, the CUFs, the environmentally-adjusted CUF (CUF_{en}), transient cycle limits, and the predicted flaw size (for a fatigue crack growth analysis). The limit of the fatigue parameter is established by the applicable fatigue analysis and may be a design limit, for example, based on the number of cyclic load occurrences assumed in a fatigue exemption evaluation; or the acceptable flaw size of a flaw identified during an in-service inspection.

The program verifies the continued acceptability of existing analyses through cycle counting. The program assures that the number of occurrences of each critical transient remains within the limits of the fatigue analyses, which in turn ensure that the analyses remain valid. For the pressurizer, the program documents the severity of operational parameters. Stress-based fatigue monitoring or other similar updates to evaluations of the fatigue analyses are not used to ensure the design or analysis-specific limit continues to be met.

The CUF_{en} is the CUF value adjusted to account for the effects of the reactor water environment on component fatigue life. For a plant, the effects of reactor water environment on fatigue are evaluated by assessing a set of sample critical components for the plant. Examples of critical components are identified in NUREG/CR-6260, “Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components;” however, plant-specific component locations in the reactor coolant pressure boundary may be more limiting than those considered in NUREG/CR-6260, and thus should be considered. Environmental effects on fatigue for these critical components may be evaluated using the guidance in Regulatory Guide (RG) 1.207, Revision 1, “Guidelines for Evaluating the Effects of Light Water Reactor Coolant Environments in Fatigue Analyses of Metal Components;” alternatively, the bases in NUREG/CR-6909, Revision 0, “Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials,” (with “average temperature” used consistent with the clarification that was added to NUREG/CR-6909, Revision 1); or other subsequent U.S. Nuclear Regulatory Commission (NRC)-endorsed alternatives.

The *Fatigue Monitoring* program relies on the *Water Chemistry* program (B2.1.2) to provide monitoring of appropriate environmental parameters for calculating environmental fatigue multipliers (F_{en} values).

The program monitors and tracks the number of occurrences of each of the critical thermal and pressure transients for the ASME Code, Section III components and USAS B31.7, Class 1 nuclear power piping EAF sentinel locations in order to maintain the CUF_{en} below unity. The program monitors design transients for ASME Code, Section III components specified in the UFSAR Section 5.2. The fatigue sensitive transients related to the USAS B31.7, Class 1 main loop reactor coolant piping are monitored by virtue that they are the same as those for the Class 1, Section III components. For the pressurizer and pressurizer surge line, the program documents the severity of operational parameters.

For certain reactor coolant system branch line piping connections subject to environmentally assisted fatigue, the program manages the effects of aging due to fatigue through the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1) by conducting inspections in accordance with ASME Code, Section XI, Nonmandatory Appendix L.

Some of the design fatigue analyses are implicit evaluations or fatigue waivers. Both of these analyses provide the basis for not requiring detailed fatigue analyses (e.g., CUF, CUF_{en}). Implicit fatigue evaluations specify allowable stress levels based on the number of anticipated full thermal range transient cycles. ASME Code, Section III Class 2 and 3 components include implicit cycle-based maximum allowable stress range calculations. Fatigue waivers may have been permitted such that a detailed fatigue calculation was not required if a component conformed to certain criteria, such as those established in ASME Code, Section III, NB-3222.4(d). The program monitors and tracks the number of critical thermal and pressure transient occurrences for the selected components and verifies that the severity of the monitored transients is bounded by the design transient definitions in order to ensure these implicit fatigue evaluations or fatigue waivers remain valid.

In some cases, flaw tolerance evaluations are used to establish inspection frequencies for components that, for example, exceed CUF or CUF_{en} fatigue limits. As an example, ASME Code, Section XI, Nonmandatory Appendix L provides guidance on the performance of fatigue flaw tolerance evaluations to determine acceptability for continued service of reactor coolant system branch line piping subjected to cyclic loadings. In flaw tolerance evaluations, the predicted size of a postulated fatigue flaw, whose initial size is typically based on the resolution of the inspection method, is a computed parameter that is used to determine the appropriate inspection frequency. The program monitors and tracks the number of occurrences of fatigue sensitive thermal and pressure transients for the selected components that are used in the fatigue flaw tolerance evaluations to verify that the inspection frequencies remain appropriate.

When a flaw is identified in an ASME Code, Section III, Class 1 vessel by in-service inspection, ASME Code, Section XI, Nonmandatory Appendices A and/or C provide guidance on the performance of flaw crack growth evaluations to determine acceptability for continued service of reactor coolant system pressure boundary components subjected to cyclic loadings. In such a case, the predicted size of an identified flaw is a computed parameter suitable for determining the appropriate inspection frequency through a fatigue crack growth evaluation. The program monitors and tracks the number of occurrences of each of the critical thermal and pressure transients for the selected components that are used in the crack growth evaluations to verify that the inspection frequencies remain appropriate.

NUREG-2191 Consistency

The *Fatigue Monitoring* program is an existing program that, following enhancement, will be consistent, with NUREG-2191, Section X.M1, Fatigue Monitoring.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program elements):

Parameters Monitored/Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5), Acceptance Criteria (Element 6), and Corrective Actions (Element 7)

1. Procedures will be revised to require monitoring and tracking of transient cycles associated with the ASME Code, Section XI, Appendix L fatigue sensitive locations to be performed each inspection interval. Consistent with the existing cycle counting program, a surveillance limit will be established to initiate corrective actions prior to exceeding transient cycle assumptions in the ASME Code, Section XI, Appendix L analyses.

Corrective Actions (Element 7)

2. Procedures will be revised to expand existing corrective action guidance associated with exceeding a cycle counting surveillance limit to recommend consideration of component repair, component replacement, performance of a more rigorous analysis, performance of an ASME Code, Section XI, Appendix L flaw tolerance analysis, or scope expansion to consider other locations with the highest expected CUF_{en} values.
3. Procedures will be revised to require that when a cycle counting action limit is reached, action will be taken to ensure that the analytical bases of the High-Energy Line Break (HELB) locations are maintained.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Fatigue Monitoring* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 2012, full structural weld overlays (FSWOLs) were installed on each of the three Unit 1 steam generator (SG) inlet nozzles (Hot Leg) as part of the Alloy 600 Aging Management Program. Fatigue is considered a TLAA for these components since there were detailed fatigue evaluations as part of the FSWOL design. The Unit 1 Hot Leg SG primary loop inlet nozzles were inspected in the spring 2009 refueling outage with no unacceptable indications. FSWOL installation was planned for the Spring 2012 refuel outage. However, prior to the FSWOL installation, two through-wall cracks were observed after machining activities on the ‘B’ SG inlet nozzle location. There was no impact on the FSWOL design.

2. In December 2014, a pressure boundary leak on the ‘B’ loop drain piping due to thermal fatigue of an elbow was discovered. Further evaluation determined that the thermal fatigue cycles assumed in the Class 1 pipe stress analysis for excess letdown were not monitored in the cycle/transient log for the reactor coolant system. The cycle/transient log was revised to add thermal cycles of excess letdown.
3. In May 2017, an assessment was performed to determine the progress and substance of license commitment closure and readiness for the IP 71003 NRC Phase II inspection conducted for Units 1 and 2 from November through December of 2017. The conclusion reached was that an area for improvement or enhancement was identified for the Augmented Inspection Activities AMA (UFSAR Section 18.2.1) involving pressurizer surge line weld inspections. A letter was submitted to the NRC providing the inspection plan for the pressurizer surge line welds to the reactor coolant system (RCS) hot leg in order to fulfill UFSAR Commitment 24. During the assessment, a review of the background information (LR application, RAIs, and NRC SER) found that inspection intervals were to be determined by a method accepted by the NRC (i.e., ASME Appendix L). Although the proposed once-per-period inspections were considered conservative, the inspection frequency was not determined by a method accepted by the NRC. Commitment 24 stated that, specifically for the Environmentally-Assisted Fatigue method, the licensee would provide the inspection details for the pressurizer surge line inspections. The NRC concluded that, based on the review of licensee actions completed at the time of this inspection and the timeliness of those actions, Commitment 24 was complete.
4. In August 2018, it was identified that power operated relief valve (PORV) operation to purge non-condensible gases from the pressurizer during cold shutdown (Mode 5) may not be appropriately counted in the transient cycle counting procedures. Procedural guidance was unclear whether the thermal transient of the pressurizer PORVs and associated piping due to manual actuations of the PORVs during unit shutdown and startup should be tracked. The Engineering evaluation determined that tracking PORV cycles performed during cold shutdown (Mode 5) operations when the pressurizer temperatures are at or below 450°F was not required. A corrective action was initiated to include guidance that when pressurizer temperature is above 450°F, PORV cycles must be counted unless the consecutive cycle occurs within 30 minutes of the previous valve stroke.
5. In April 2019, an effectiveness review was performed on the Augmented Inspections Activities AMA (UFSAR Section 18.2.1) involving pressurizer surge line weld inspections and MRP-146Thermal Fatigue in Normally Stagnant Non-Isolable RCS Branch Lines.” The AMA was evaluated against the performance criteria identified in NEI 14-12, “Aging Management Program Effectiveness.” No gaps were identified by the effectiveness review.

The above examples of operating experience provide objective evidence that the *Fatigue Monitoring* program includes activities to identify and manage cycle-based fatigue of the mechanical or structural components with a fatigue time-limited aging analysis (TLAA) or other analysis that depends on the number of occurrences and severity of transient cycles within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Fatigue Monitoring* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Fatigue Monitoring* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Fatigue Monitoring* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B3.2 Neutron Fluence Monitoring

Program Description

The *Neutron Fluence Monitoring* program is an existing condition monitoring program that manages loss of fracture toughness due to neutron fluence of the reactor vessel (RV) regions for which neutron fluence is projected to exceed 1 x 10^{17} n/cm^2 (E>1MeV) during the subsequent period of extended operation to ensure that applicable reactor pressure vessel neutron irradiation embrittlement analysis will remain within their applicable limits.

The program includes provisions to calculate and evaluate RV neutron fluence projections for the RV beltline and extended beltline; withdraw and test reactor in-vessel material surveillance capsules, dosimeters, and thermal monitors; use the calculated fluence projections as inputs to perform pressurized thermal shock (PTS) assessments in accordance with 10 CFR 50.61; calculate Pressure/Temperature (P-T) Limit Curves and Low Temperature Overpressure Protection System (LTOPS) setpoints, and assess upper shelf energy (USE) in accordance with 10 CFR 50, Appendix G; and track/project Effective Full-Power Years (EFPY) for P-T curve applicability and scheduling capsule withdrawals.

Reload verification of assumed reactor vessel fluence values on a cycle-by-cycle basis is performed based on calculations of the cumulative average unit capacity factor and cumulative-average-weighted reload Relative (radial) Power Distributions (RPDs) of peripheral core locations.

The methods and assumptions for determining RV neutron fluence for the beltline region are consistent with NRC Regulatory Guide (RG) 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.”

For the extended beltline region (materials outside the RV beltline region that are projected to exceed 1 × 10^{17} n/cm^2 (E > 1 MeV) during the subsequent period of extended operation), the methods, assumptions and results of neutron fluence calculations are described in WCAP-18015-NP, “Extended Beltline Pressure Vessel Fluence Evaluations Applicable to North Anna 1 & 2." In the plant-specific WCAP, the use of RG 1.190-adherent methods to estimate neutron fluence for the extended beltline regions was justified due to 1) the close proximity (regions approximately 1 ft below and 4 ft above) of the RV beltline region immediately surrounding the reactor core, and 2) the North Anna-specific neutron fluence calculations for the RV beltline materials agree with the fluence measurements from the tested surveillance capsule dosimetry. The methods used to identify the fluence for the materials within the extended beltline region are consistent with RG 1.190. While the fluence projections for the inlet and outlet nozzles may have greater uncertainty than other beltline materials, these fluence projections are acceptable for performing RV integrity assessments for the subsequent license renewal period. The basis for this determination is discussed in Section 4.2.1, Neutron Fluence Projections.

For reactor vessel internals (RVI), the Electric Power Research Institute Materials Reliability Program (MRP) conducted an expert panel to evaluate the neutron fluence impacts on the susceptibility of RVI components to neutron radiation damage mechanisms (including irradiation embrittlement, irradiated-assisted stress corrosion cracking, irradiation-enhanced stress relaxation or creep and void swelling or neutron induced component distortion), during the development of reactor vessel internals aging management guidance. A gap analysis evaluated the impact of “Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines,” MRP-227-A, inspection recommendations for the subsequent period of extended operation. The gap analysis included plant-specific 80-year neutron fluence values for RVI components that were calculated using NRC-approved methodologies, a plant-specific RVI component model, and a plant-specific core neutron source conforming to RG 1.190. The 80-year plant-specific neutron fluence values for RVI components were evaluated using the material-specific degradation thresholds in the RVI gap analysis. Ongoing inspections of RVI components for the above radiation damage mechanisms and associated degradation thresholds are performed consistent with the *PWR Vessel Internals* program (B2.1.7); therefore neutron fluence monitoring for the RVI is not required.

There are sufficient surveillance capsules remaining in-vessel to evaluate the subsequent license renewal period of extended operation so that ex-vessel capsules are not required.

The *Neutron Fluence Monitoring* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *Neutron Fluence Monitoring* program is an existing program that is consistent with NUREG-2191, Section X.M2, Neutron Fluence Monitoring as modified by SLR-ISG-Mechanical-2020-XX, Updated Aging Management Criteria for Mechanical Portions of the Subsequent License Renewal Guidance.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Neutron Fluence Monitoring* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In 1999, the Unit 1 Capsule W examination results report determined that the specimens in Unit 1 Capsule W were exposed to fluences equivalent to approximately 2.052 X 10^{19} n/cm^2 based on the calculated fluence and satisfy the USE criterion and the PTS reference temperature screening criteria. The adjusted reference temperatures were shown to be less than those used in the Unit 1 P-T limit curves, thereby demonstrating margin in the operating limits.
2. In 2000, the Unit 2 Capsule W examination results report determined that specimens in Unit 2 Capsule W were exposed to fluences equivalent to approximately 2.092 X 10^{19} n/cm^2 based on the calculated fluence and satisfy USE criterion and the PTS reference temperature screening criteria. The adjusted reference temperatures were shown to be less than those used in the Unit 2 P-T limit curves, thereby demonstrating margin in the operating limits.
3. In 2009, a licensee amendment request (LAR) (ADAMS Accession No. ML090900055) summarized program impact reviews performed for a 1.6% Measurement Uncertainty Recapture (MUR) power uprate (PU). At the time of the LAR, End of Life (EOL) referred to a 60-year license. In the Safety Evaluation Report issued by the NRC (ADAMS Accession No. ML092250616), the NRC staff concluded the fluence values for the MUR are bounded by the fluence values used to determine the initial license renewal EOL condition for Units 1 and 2, and therefore:
    a. The RV surveillance programs will continue to meet the requirements of 10 CFR Part 50, Appendix H under the MUR PU.
    b. The P-T limits and LTOPS setpoints would continue to meet the requirements of 10 CFR Part 50, Appendix G under the MUR PU.
    c. The RV materials would continue to meet the USE criteria requirements of 10 CFR Part 50, Appendix G under the MUR PU.
    d. The RV materials would continue to meet the PTS screening criteria requirements of 10 CFR 50.61.
    e. The minimal changes in operating temperatures are not expected to have any significant impact on irradiation-related aging degradation of RVI components.

4. In 2014, in response to Westinghouse letter MCOE-LTR-14-17, Rev 0, “Applicability of the Pressure-Temperature Limit Curve Figures During Vacuum Refill of the RCS in Mode 5 for Westinghouse and CE NSSS Plants,” The Unit 1 and Unit 2 P-T limit curves were revised and transmitted them to NRC for review and approval. NRC issued RAIs on the fluence projections to the nozzle materials located outside the traditional beltline region. Revision to the capsule withdrawal schedule and lead factors resulting from the revised fluence projections is discussed in the *Reactor Vessel Material Surveillance* program (B2.1.19). Updated fluence projections are documented in WCAP-18015, Revision 1.

The above examples of operating experience provide objective evidence that the *Neutron Fluence Monitoring* program includes activities to identify loss of fracture toughness due to neutron fluence for components susceptible to neutron embrittlement within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Neutron Fluence Monitoring* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Neutron Fluence Monitoring* program will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Neutron Fluence Monitoring* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B3.3 Environmental Qualification of Electric Equipment

Program Description

The *Environmental Qualification of Electric Equipment* program is an existing program that manages equipment thermal, radiation, and cyclical aging through the use of aging evaluations based on 10 CFR 50.49 qualification methods. This program implements the environmental qualification (EQ) requirements of 10 CFR 50.49. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical equipment located in harsh plant environments will perform applicable safety functions in those harsh environments after the effects of in-service aging. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification.

The EQ program for Unit 1 was evaluated against the Division of Operating Reactors (DOR) Guidelines and the basis for Equipment Qualification is Inspection and Enforcement Bulletin (IEB) 79-01B and IEEE Standard 323-1974, as codified by 10 CFR 50.49. The basis for Unit 2 is IEEE Standard 323-1974 and NUREG-0588, Category II, as codified by 10 CFR 50.49. IEEE 323-1974 provides the criteria for safety related equipment (electrical “Class 1E” equipment) and the basis for categorizing components important to safety, and defines environmental service conditions. Therefore, the EQ program includes and identifies electrical components that are important to safety and could be exposed to harsh environment accident conditions, as defined in 10 CFR 50.49.

As required by 10 CFR 50.49, EQ equipment not qualified for the current license term is refurbished or replaced, or has its qualified life extended through reanalysis or ongoing qualification prior to reaching the designated life aging limits established in the evaluation. Aging evaluations for EQ equipment that specify a qualified life of 40 to 60 years are time-limited aging analyses (TLAAs) for subsequent license renewal.

Reanalysis of an aging evaluation to extend the qualification of equipment qualified under the program requirements of 10 CFR 50.49(e) is performed as part of the EQ program. 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).

Analytical Methods: The analytical models used in the reanalysis of an aging evaluation are the same as those previously applied during the prior evaluation. The Arrhenius methodology is an acceptable thermal model for performing a thermal aging evaluation. An acceptable method for establishing the 80-year normal radiation dose is to multiply the 40-year normal radiation dose by two, with the result being added to the accident radiation dose to obtain the total integrated dose for the component. A similar approach may be used for cyclical aging.

Data Collection and Reduction Methods: The identification of excess conservatism in electrical equipment service conditions (for example, temperature, radiation, and cycles) used in the prior aging evaluation is the chief method used for a reanalysis. Temperature data and uncertainties used in an equipment EQ evaluation should be based on plant design temperatures or on actual plant temperature data. A representative number of temperature measurements over a sufficient period of time are evaluated to establish the temperatures used in an aging evaluation. Similar methods of identifying excess conservatism in the equipment service condition evaluation may be used for radiation and cyclical aging. Changes to material activation energy values as part of a reanalysis are justified.

Underlying Assumptions: EQ equipment aging evaluations account for environmental changes occurring due to plant modifications and events. A reanalysis demonstrates that adequate margin is maintained consistent with the original analysis in accordance with 10 CFR 50.49 requiring certain margins and accounting for the unquantified uncertainties established in the EQ aging evaluation of the equipment. Although areas within a nuclear power plant may experience actual ambient environments that are less severe than the anticipated plant design environment, in a limited number of localized areas, the actual environments may be more severe than the plant design environment considered for EQ equipment. These adverse localized environments are addressed in an EQ reanalysis. Accessible passive EQ electrical equipment within the scope of subsequent license renewal will be inspected at least once every ten years to identify EQ electrical equipment subjected to an adverse localized environment with the first inspection performed prior to the subsequent period of extended operation.

Acceptance Criteria and Corrective Actions: Reanalysis of an aging evaluation can be used to extend the environmental qualification of the equipment. If the qualification cannot be extended by reanalysis, the equipment is refurbished, replaced, or requalified prior to exceeding the current qualified life.

When the reanalysis assessed margins, conservatisms, or assumptions do not support reanalysis (e.g., extending qualified life) of EQ equipment, the use of on-going qualification techniques including condition monitoring or condition based methodologies may be implemented. Ongoing qualification is an alternative means to provide reasonable assurance that an equipment environmental qualification is maintained for the subsequent period of extended operation. Ongoing qualification of electric equipment important to safety subject to the requirements of 10 CFR 50.49 involves the inspection, observation, measurement, or trending of one or more indicators, which can be correlated to the condition or functional performance of the EQ equipment. Ongoing qualification techniques for EQ equipment include periodic testing, inspections, mitigation, and sampling (e.g., subsequent EQ qualification testing of inservice or representative EQ equipment with established acceptance criteria and corrective actions, mitigation, replacement or refurbishment) consistent with endorsed standards and regulatory guidance.

The *Environmental Qualification of Electric Equipment* program is implemented as a Fleet program at Dominion. The Fleet program requirements and Fleet implementation procedures have been previously reviewed and evaluated by the NRC Staff and a determination was made that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the subsequent period of extended operation, as required by 10 CFR 54.21(a)(3) (ADAMS Accession No. ML19360A020).

NUREG-2191 Consistency

The *Environmental Qualification of Electric Equipment* program is an existing program that is consistent with NUREG-2191, Section X.E1, Environmental Qualification of Electric Equipment.

Exception Summary

None

Enhancements

None

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Environmental Qualification of Electric Equipment* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that the intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In April 2010, a review of the preventive maintenance schedule identified two solenoid operated valves (SOV) with qualified life replacement intervals that would expire prior to replacement during the next unit outage. Qualified life for these two SOVs was extended by reanalysis using excess thermal margin in the specific EQ zone. Two maintenance task evaluations with incorrect information caused a schedule issue with these two SOVs that affected a total of 16 of 154 valves. Replacement intervals were corrected for the affected valves. No SOVs exceeded their qualified life replacement dates.
2. In April 2012, a solenoid operated valve was discovered to be installed in the plant for 2 years beyond its replacement date due to a work order statusing issue. Qualified life was reanalyzed based on margin in the projected cycle rate over the actual cycle rate, and it was determined that qualified life had not been exceeded. The SOV was replaced during the 2012 refueling outage. The method for canceling work orders has since been changed to prevent this type of occurrence.
3. In October 2015, Steris-Isomedix™ issued a Part 21 notification concerning unidentified uncertainties in the radiation doses applied during qualification testing. This resulted in actual radiation doses as much as 10% lower than reported. The affected equipment qualification documents were identified and evaluated, with no adverse environmental qualification impacts.

4. In August 2016, it was determined that equipment qualification files for Rockbestos and Brand-Rex cable did not adequately address beta radiation dose for unjacketed or limited jacketing SIS wire. The effect of beta radiation was analyzed and found to be bounded by the existing gamma radiation dose used to qualify the motor operated valves. The affected cable qualification reports were updated to include the effects of beta radiation.
5. In September 2017, it was determined during a review of Namco Limit Switch EQ files that several discrepancies existed including questions regarding the correct test report referenced, component temperature rise concerns, mounting and orientation concerns, and proper translation of test report requirements to plant maintenance documents. Engineering performed field walkdowns and document reviews to evaluate these issues and determined that Namco limit switches remained fully qualified under 10 CFR 50.49.
6. In February 2018, a report was issued to document a self-assessment of the EQ program for programmatic and regulatory compliance, and for appropriate configuration management of the EQ program and EQ-related equipment. No cross-cutting programmatic elements were identified during the review and no areas for improvement were noted. A number of recommendations were developed for further technical and programmatic improvements.
7. In May 2019, a Design Basis Assurance Inspection was conducted on the EQ program. The inspection yielded a green non-cited violation against 10 CFR 50 Appendix B, Criteria III for failure to comply with design control documents, a green non-cited violation against 10 CFR 50.49(e)(3) for failure to qualify electric equipment for the most severe chemical effects in accordance with regulatory and industry guidance, an unresolved item involving complete and accurate information provided for a license amendment request, and several minor violations and findings. Each case was evaluated by engineering and determined to be a documentation issue. The qualified life of installed equipment was not affected by these issues and the equipment remains fully qualified under 10 CFR 50.49. The non-cited violations and the unresolved item have been closed.

The above examples of operating experience provide objective evidence that the *Environmental Qualification of Electric Equipment* program includes activities to perform audits and document reviews to identify thermal, radiation, and cyclical aging effects for qualified electrical equipment within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Environmental Qualification of Electric Equipment* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Environmental Qualification of Electric Equipment* program will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Environmental Qualification of Electric Equipment* program provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

North Anna Power Station

Units 1 and 2

Application for Subsequent License Renewal

Appendix C
MRP-227-A Gap Analysis for PWR Vessel Internals Aging Management

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APPENDIX C

C1 INTRODUCTION

This appendix is not needed for the North Anna Subsequent License Renewal application.

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North Anna Power Station

Units 1 and 2

Application for Subsequent License Renewal

Appendix D
Technical Specification Changes

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APPENDIX D

TECHNICAL SPECIFICATION CHANGES

10 CFR 54.22 requires that an application for license renewal include any Technical Specification changes or additions necessary to manage the effects of aging during the period of extended operation.

No Technical Specification changes or additions were identified as necessary to manage the effects of aging during the subsequent period of extended operation and as such no Technical Specification changes or additions are included with this Subsequent License Renewal Application.

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