TENNESSEE VALLEY AUTHORITY

1101 Market Street, Chattanooga, Tennessee 37402

CNL-24-001

January 19, 2024

10 CFR 50
10 CFR 51
10 CFR 54

ATTN: Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001

Browns Ferry Nuclear Plant, Units 1, 2, and 3
Renewed Facility Operating License Nos. DPR-33, DPR-52, and DPR-68
NRC Docket Nos. 50-259, 50-260, and 50-296

Subject: **Browns Ferry Nuclear Plant, Units 1, 2, and 3 – Application for Subsequent Renewed Operating Licenses**

Pursuant to Title 10 of the *Code of Federal Regulations*, Part 50, "Domestic Licensing of Production and Utilization Facilities," Part 51, "Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions," and Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," the Tennessee Valley Authority (TVA) applies for the renewal of the Browns Ferry Nuclear Plant (BFN), Units 1, 2, and 3, Renewed Facility Operating Licenses, Nos. DPR-33, DPR-52, and DPR-68, respectively. The first Renewed Facility Operating Licenses for BFN Units 1, 2, and 3 were issued on May 4, 2006, and will expire at midnight on December 20, 2033, June 28, 2034, and July 2, 2036, respectively.

TVA seeks to extend the operating term of the BFN units by 20 years beyond the current renewal license expiration dates.

The enclosed Subsequent License Renewal Application (SLRA) contains the information required by 10 CFR Parts 54 and 51 and meets the submittal timeliness requirements of 10 CFR 54.17(c) and 10 CFR 2.109(b). This submittal provides appropriate administrative, technical, and environmental information sufficient to support Nuclear Regulatory Commission (NRC) findings required by 10 CFR 54.29.

Enclosure 1 of this letter provides BFN SLRA Sections 1 through 4 and Appendices A through D. Enclosure 2 of this letter provides BFN SLRA Appendix E, Applicant's Environmental Report-Operating License Renewal Stage. Enclosure 3 of this letter provides the proprietary version of BFN SLRA Section 4, Time-Limited Aging Analyses. Electric Power Research Institute (EPRI) and General Electric Hitachi (GEH) separately consider portions of the information provided in Enclosure 3 of this letter to be proprietary and, therefore, exempt from public disclosure pursuant to 10 CFR 2.390, "Public Inspections, Exemptions, Requests for Withholding." Affidavits for withholding information, executed by EPRI and GEH, are provided in Enclosure 4, respectively. A non-proprietary version of BFN SLRA Section 4 is provided in Enclosure 1. Therefore, on behalf of EPRI and GEH, TVA requests that Enclosure 3 of this letter be withheld from public disclosure in accordance with the EPRI and GEH affidavits and the provisions of 10 CFR 2.390.

As part of this application, TVA also requests NRC approval to implement BWRVIP-321 Revision 1-A, "Boiling Water Reactor Vessel and Internals Project, Plan for Extension of the BWR Integrated Surveillance (ISP) Through the Second License Renewal (SLR)," as required by NRC Safety Evaluation included in BWRVIP-321 Revision 1-A and per 10 CFR Part 50, Appendix H, Paragraph III.B.3. The commitment to implement BWRVIP-321 Revision 1-A upon obtaining NRC approval is provided as an enhancement of the Reactor Vessel Material Surveillance Program as shown in SLRA Table A.5, Commitment Number 19.1, and B.2.1.19.

As required by 10 CFR 54.21(b), current licensing basis changes which have a material effect on the content of this application will be submitted at least annually while the application is under NRC review and at least three months prior to the scheduled completion of the NRC review.

Appendix A, Table A.5, "Subsequent License Renewal Commitment List," of the enclosed BFN SLRA provides a list of commitments made in this application. This list will be updated as required throughout the SLRA review process.

Should you have any questions regarding this submittal, please contact Peter J. Donahue, Director, Subsequent License Renewal, at pjdonahue@tva.gov.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 19th day of January 2024.

Respectfully,

Kimly D. Hulvey

Digitally signed by Edmondson, Carla
Date: 2024.01.19 06:43:03 -05'00'

Kim Hulvey
Director, Nuclear Regulatory Affairs

Enclosures

cc: See Page 3

Enclosures

1. Browns Ferry Nuclear Plant Subsequent License Renewal Application Sections 1 through 4 and Appendices A through D (non-proprietary version)
2. Browns Ferry Nuclear Plant Subsequent License Renewal Application Appendix E, Applicant's Environmental Report-Operating License Renewal Stage
3. Browns Ferry Nuclear Plant Subsequent License Renewal Application Section 4, Time-Limited Aging Analyses (proprietary version)
4. Affidavits

cc:

NRC Regional Administrator – Region II
NRC Branch Chief – Region II
NRC Senior Resident Inspector – Browns Ferry Nuclear Plant
NRC Project Manager, License Renewal Projects Branch (Safety)
NRC Project Manager, License Renewal Projects Branch (Environmental)
State Health Officer, Alabama Department of Public Health (w/o Enclosure 3)

ENCLOSURE 1

Browns Ferry Nuclear Plant Subsequent License Renewal Application
Sections 1 through 4 and Appendices A through D

(non-proprietary version)

Subsequent License Renewal Application

Tennessee Valley Authority

Browns Ferry Nuclear Plant

Units 1, 2, and 3

Renewed Facility Operating License Nos.

DPR-33, DPR-52, and DPR-68

NRC Docket Nos.

50-259, 50-260, and 50-296

January 2024

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1.1 GENERAL INFORMATION

1.1.1 Name of Applicant

The Tennessee Valley Authority (TVA) is the SLR Applicant. The Browns Ferry Nuclear Plant (BFN) Site is owned by the United States of America and managed by TVA, a corporate agency of the United States of America created by an act of Congress. TVA manages and operates the BFN units installed on the BFN Site.

1.1.2 Address of Applicant

Tennessee Valley Authority
400 West Summit Hill Drive
Knoxville, TN 37902
865-632-2101

1.1.3 Description of Business or Occupation of Applicant

TVA, a corporate agency and instrumentality of the United States, was created in 1933 by the United States Congress by virtue of the Tennessee Valley Authority Act of 1933, as amended, 16 U.S.C. §§ 831-831ee (as amended). TVA was created to, among other things, improve navigation on the Tennessee River, reduce the damage from destructive flood waters within the Tennessee River system and downstream on the lower Ohio and Mississippi Rivers, further the economic development of TVA's service area in the southeastern United States, and sell the electricity generated at the facilities TVA operates.

TVA supplies power in most of Tennessee, northern Alabama, northeastern Mississippi, and southwestern Kentucky and in portions of northern Georgia, western North Carolina, and southwestern Virginia to a population of over 10 million people.

The current BFN Units 1, 2 and 3 renewed facility operating licenses will expire as follows:

- At midnight on December 20, 2033 for BFN Unit 1 (Renewed Facility Operating License No. DPR-33).
- At midnight on June 28, 2034 for BFN Unit 2 (Renewed Facility Operating License No. DPR-52).
- At midnight on July 2, 2036 for BFN Unit 3 (Renewed Facility Operating License No. DPR-68).

TVA will continue as the licensed operator on the subsequently renewed facility operating licenses.

1.1.4 Description of Organization and Management of Applicant

TVA is administered by a eight-member Board of Directors (Board) appointed by the President of the United States with the advice and consent of the U.S. Senate. All Board members are United States citizens. TVA Board members serve five-year terms, and at least one member's term ends each year. The TVA Board, among other things, establishes broad goals, objectives, and policies for TVA; develops long-range plans to guide TVA in achieving these goals, objectives, and policies;

approves annual budgets; and establishes a compensation plan for employees. Board members select the Chair of the Board.

The business address for the TVA Board is:

Tennessee Valley Authority Board of Directors
400 West Summit Hill Drive, WT7
Knoxville, TN 37902

As of the date of this application, the names of the board members are as follows:

- Beth Geer
- Beth Harwell
- Bobby Klein
- Michelle Moore
- Brian Noland
- Bill Renick
- Joe Ritch (Chair)
- Wade White

The TVA Act gives the TVA Board sole responsibility for establishing the rates TVA charges for power. These rates are not subject to review or approval by any state or Federal regulatory body.

The President and Chief Executive Officer is a United States citizen, who is selected by the Board of Directors and is the senior executive responsible for TVA's day-to-day operations. The names, titles, and addresses of the principal executives and officers of TVA, all of whom are United States citizens, are as follows:

Jeffrey J. Lyash	President and Chief Executive Officer	Tennessee Valley Authority 400 West Summit Hill Drive Knoxville, TN 37902
Donald A. Moal	Executive Vice President and Chief Operating Officer	Tennessee Valley Authority 400 West Summit Hill Drive Knoxville, TN 37902
Timothy S. Rausch	Executive Vice President and Chief Nuclear Officer	Tennessee Valley Authority 1101 Market Street Chattanooga, TN 37402
David Fountain	Executive Vice President and General Counsel	Tennessee Valley Authority 400 West Summit Hill Drive Knoxville, TN 37902

John M. Thomas	Executive Vice President and Chief Financial and Strategy Officer	Tennessee Valley Authority 1101 Market Street Chattanooga, TN 37402
Jeanette Mills	Executive Vice President and Chief External Relations Officer	Tennessee Valley Authority 400 West Summit Hill Drive Knoxville, TN 37902

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

TVA requests a subsequent renewal of the Class 104b operating licenses for BFN Units 1, 2 and 3, for a period of 20 years beyond the expiration of the current licenses to allow continued use of the facilities for the commercial generation of electricity. BFN Unit 1 license (DPR-33) expires at midnight on December 20, 2033. BFN Unit 2 license (DPR-52) expires at midnight on June 28, 2034. BFN Unit 3 license (DPR- 68) expires at midnight on July 2, 2036.

In this application, TVA also requests the renewal of specific licenses under 10 CFR Parts 30, 40, and 70 that are subsumed in or combined with the current operating licenses.

1.1.6 Earliest and Latest Dates for Alterations, if Proposed

The BFN Subsequent License Renewal Application (SLRA) does not require new construction or modifications beyond normal maintenance. TVA has no plans for refurbishment or replacement activities, outside of normal maintenance, at BFN associated with SLRA.

1.1.7 Restricted Data

With regard to the requirements of 10 CFR 54.17(f), this application 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 not expected that any such information will be part of the licensed activities.

In accordance with the requirements of 10 CFR 54.17(g), the applicant 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

As required by its founding charter, the Tennessee Valley Authority Act of 1933, TVA sets rates for electric power which will produce revenues sufficient to provide funds for operation, maintenance, and administration of its power system. No other regulatory agencies have jurisdiction over TVA's rates and services.

1.1.9 Local News Publications

News publications in circulation near BFN that are considered appropriate to give reasonable notice of the application are as follows:

The News Courier
410 West Green Street
Athens, AL 35612

The Decatur Daily
201 1st Ave SE
Decatur, AL 35601

The Huntsville Times
2317 Memorial Pkwy SW
Huntsville, AL 35801

Courier Journal
219 W. Tennessee St.
Florence, AL 35630

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 renewal license." TVA requests that, as appropriate, conforming changes be made to Article VII of the indemnity agreement and Item 3 of the Attachment to that agreement, specifying the extension of agreement until the expiration date of the subsequent renewed facility operating licenses as sought in this application. TVA understands that no changes may be necessary for this purpose if the current license numbers for BFN Units 1, 2, and 3 are retained.

1.2 GENERAL LICENSE INFORMATION

1.2.1 Application Updates, Renewed Licenses, and Renewal Term Operation

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

In accordance with 10 CFR 54.21(d), TVA will maintain a summary description in the BFN Final Safety Analysis Report (FSAR) of programs and activities that are required to manage the effects of aging for the systems, structures, and components determined to be subject to aging management during the subsequent period of extended operation, and summaries of the Time-Limited Aging Analyses (TLAAs) evaluations.

1.2.2 Incorporation by Reference

There are no documents incorporated by reference as part of the application. Any document references, either in text or in Section 1.7, are listed for information only.

1.2.3 Contact Information

In addition to the BFN service list, all communications concerning this application should be copied to the following:

Pete Donahue
Director, Subsequent License Renewal
Post Office Box 2000
Decatur, AL 35609-2000

Tennessee Valley Authority
e-mail: pjdonahue@tva.gov

1.3 PURPOSE

This document provides information required by 10 CFR 54 to support the application for subsequent renewed licenses for BFN Units 1, 2 and 3. The application 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

BFN Units 1, 2, and 3 are boiling water reactors (BWRs) located on the north shore of Wheeler Reservoir in Limestone County, Alabama, at Tennessee River Mile (TRM) 294. The site contains approximately 880 acres and is located approximately 30 miles west of Huntsville, Alabama. The plant is located on property owned by the United States and in the custody of TVA.

BFN Units 1, 2 and 3 are designed and supplied by General Electric with 251-inch diameter reactor vessels and 764 fuel assemblies. The primary containment of each unit is a Mark I design, consisting of a drywell, a suppression chamber in the shape of a torus, and a connecting vent system between the drywell and the suppression chamber. The reactor building is shared by all three units. The turbine building, control bay, radwaste building, diesel generator building, and intake pumping station house equipment used by all three units.

Each BFN unit was originally authorized to operate at steady state reactor core power levels not in excess of 3293 megawatts thermal (MWt). In 2007, for Unit 1 (ADAMS Accession No. ML063350404), and 1998, for Units 2 and 3 (ADAMS Accession No. ML020100022), the NRC granted power uprates allowing the BFN units to be operated at a maximum power level of 3458 MWt based upon original steam flow capability above rated power, improved analytical techniques, and more current fuel design.

An Extended Power Uprate (EPU) project was undertaken for the three units, resulting in maximum core power levels of 3952 MWt being approved by the NRC in August 2017 (ADAMS Accession No. ML17032A120). The bases for these increased allowable power levels included continuing improvements in analytical techniques, fuel and core design, and plant hardware modifications, enabling plant power to be increased to approximately 20 percent above original licensed thermal power.

1.5 APPLICATION STRUCTURE

This license renewal application is structured in accordance with Regulatory Guide 1.188, “Standard Format and Content for Applications to Renew Nuclear Plant Operating Licenses,” and NEI 17-01, “Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal.” 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.” NUREG-2192 (SRP-SLR) references NUREG-2191, “Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report.” 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.

The application is divided into the following major sections:

Section 1 – Administrative Information

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

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

This section describes and justifies the methods used in the integrated plant assessment to identify those systems, 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 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 systems, structures, and components that perform their intended function 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 and screening results for systems and structures are described in this section. Scoping results are presented in Section 2.2, “Plant Level Scoping Results.” Screening results are presented in Sections 2.3, 2.4, and 2.5.

The screening results consist of lists of passive long-lived mechanical and structural components that require aging management review. Brief descriptions of mechanical systems and structures within the scope of subsequent license renewal are provided as background information. Mechanical system and structure intended functions are provided for in scope systems and structures. For each in scope system and structure, components requiring an aging management review are identified; associated component intended functions are identified; and appropriate reference to the Section 3 table providing the aging management review results is made.

Electrical components and selected structural components, such as electrical insulation for electrical cables and connections and component supports, respectively, were evaluated as commodities. Under the commodity approach, components were evaluated based upon common environments and materials. Components requiring an aging management review are presented in Sections 2.4 and 2.5. Component intended functions and reference to the applicable Section 3 table is provided.

The descriptions of systems in Section 2 identify subsequent license renewal boundary drawings that depict the components subject to aging management review for mechanical systems. These drawings are provided in a separate submittal.

Section 3 – Aging Management Review Results

10 CFR 54.21(a)(3) requires a demonstration that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the current licensing basis throughout the subsequent period of extended operation. Section 3 presents the results of the aging management reviews. Section 3 provides the link between the scoping and screening results provided in Section 2, the Aging Management Programs (AMPs) provided in Appendix B, and the TLAA evaluations provided in Section 4.

Aging management review results are presented in tabular form, in a format in accordance with NUREG-2192, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants." For mechanical systems, Aging Management Review (AMR) results are provided in Sections 3.1 through 3.4 for the Reactor Vessel, Internals, and Reactor Coolant System; Engineered Safety Features and Reactor Core Isolation Cooling System; Auxiliary Systems; and Steam and Power Conversion Systems, respectively. AMR results for Containments, Structures, and Component Supports are provided in Section 3.5. AMR results for electrical and instrumentation and controls (I&C) Systems are provided in Section 3.6.

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

Section 4 – Time-Limited Aging Analyses

TLAAs, as defined in 10 CFR 54.3, are listed in this section. This section includes a screening of the generic TLAAs identified in NUREG-2192 and the results of a review of the current licensing basis for plant-specific TLAAs. This section includes a summary of the time-dependent aspects of the analyses. A demonstration is provided to show that the analyses remain valid for the subsequent period of extended operation, the analyses have been projected to the end of the subsequent period of extended operation, or the effects of aging on the intended function(s) will be adequately managed for the subsequent period of extended operation, consistent with 10 CFR 54.21(c)(1)(i)-(iii).

Appendix A – Final Safety Analysis Report Supplement

As required by 10 CFR 54.21(d), the FSAR supplement contains a summary of activities credited for managing the effects of aging for the subsequent period of extended operation. In addition, summary descriptions of TLAA evaluations are provided. NUREG-2191 Tables X-01 and XI-01, FSAR Supplement Summaries for GALL-SLR Report Chapters X and XI Aging Management Programs, respectively, were used as guidance for the content of the applicable AMP summaries. Following issuance of the subsequently renewed licenses, the information contained in this appendix, as updated through the NRC review process, will be incorporated into the FSAR.

Appendix B – Aging Management Programs

Appendix B describes the programs and activities 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. Sections B.2 and B.3 discuss those programs that are contained in Section XI and Section X, respectively, of NUREG-2191. A description of the AMP is provided and a conclusion is drawn based upon the results of an evaluation to each of the ten elements provided in NUREG-2191. In some cases, exceptions and justifications for managing aging are provided for specific NUREG-2191 program elements. Additionally, operating experience related to the AMP is provided, including an assessment of the effectiveness of aging management activities in place for the initial period of extended operation, where applicable.

Appendix C – Response to BWRVIP License Renewal Applicant Action Items

This Appendix provides the requested responses to applicant action items contained in the NRC Safety Evaluation Reports associated with NRC approved Boiling Water Reactor Vessel and Internals Project (BWRVIP) reports.

Appendix D – Technical Specification Changes

This Appendix satisfies the requirement in 10 CFR 54.22 to identify technical specification changes or additions necessary to manage the effects of aging during the subsequent period of extended operation.

Appendix E – Applicant's Environmental Report - Operating License Renewal Stage

This Appendix 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 for BFN Units 1, 2 and 3.

1.6 ACRONYMS

Acronym	Meaning
AAC	All Aluminum Conductor
AC	Alternating Current
ACAR	Aluminum Conductor Aluminum Alloy Reinforced
ACI	American Concrete Institute
ACSR	Aluminum Conductor Steel Reinforced
ACSS	Aluminum Conductor Steel Supported
ADHR	Alternate Decay Heat Removal
ADS	Automatic Depressurization System
AERMs	Aging Effects Requiring Management
AISC	American Institute of Steel Construction
ALE	Adverse Localized Environment
ALT	Alternate Leakage Treatment
AMP	Aging Management Program
AMR	Aging Management Review
ANSI	American National Standards Institute
AOT	Abnormal Operational Transient
ARI	Alternate Rod Insertion
ART	Adjusted Reference Temperature

Acronym	Meaning
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
ASR	Alkali-Silica Reaction
AST	Alternative Source Term
ASTM	American Society for Testing and Materials
ATWS	Anticipated Transient Without Scram
AWWA	American Water Works Association
BFN	Browns Ferry Nuclear Plant
BLEU	Blended Low Enriched Uranium
BTP	Branch Technical Position
BWR	Boiling Water Reactor
BWRVIP	Boiling Water Reactor Vessel and Internals Project
C (ºC)	Degrees Celsius
CAD	Containment Atmosphere Dilution
CAP	Corrective Action Program
CASS	Cast Austenitic Stainless Steel
CBS	Containment Biological Shield
CCW	Condenser Circulation Water
CF	Chemistry Factor
CFR	Code of Federal Regulations
CGU	Commercial Grade Uranium
CLB	Current Licensing Basis
CLTP	Current Licensed Thermal Power
CMAA	Crane Manufacturers Association of America
CMTR	Certified Material Test Report
CO_2	Carbon Dioxide
CO_2/FP	Carbon Dioxide Storage Fire Protection/Purging
CR	Condition Report
CRD	Control Rod Drive
CRGT	Control Rod Guide Tube
CREV	Control Room Emergency Ventilation
CRHZ	Control Room Habitability Zone
CS	Carbon Steel
CSST	Common Station Service Transformer
CTT	Cooling Tower Transformer
CTWS	Closed Treated Water Systems

Acronym	Meaning
CUF	Cumulative Usage Factor
CUF_{en}	Environmentally Adjusted Cumulative Usage Factor
DBA	Design Basis Accident
DBE	Design Basis Event
DC	Direct Current
DCD	Design Criteria Document
DCV	Directional Control Valve
DDFP	Diesel-Driven Fire Protection
DOE	Department of Energy
DORT	Discrete Ordinates Transfer
DP	Differential Pressure
dpa	Displacement Per Atom
EAF	Environmentally-Assisted Fatigue
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EECW	Emergency Equipment Cooling Water
EG-R	Electronic Governor
EHPM	Emergency High Pressure Makeup
EMA	Equivalent Margin Analysis
EFPY	Effective Full Power Years
EOI	End of Interval
EOL	End of Life
EPDM	Ethylene-Propylene Diene Monomer
EPR	Ethylene-Propylene Rubber
EPRI	Electric Power Research Institute
EPU	Extended Power Uprate
ERFBS	Electrical Raceway Fire Barrier System
EQ	Environmental Qualification
ESF	Engineered Safety Features
EVT	Enhanced Visual Examination
EWR	Engineering Work Request
F (ºF)	Degrees Fahrenheit
FAC	Flow-Accelerated Corrosion
F_{en}	Environmentally Assisted Fatigue Correction Factor
FERC	Federal Energy Regulatory Commission
FLEX	Diverse and Flexible Coping Strategies

Acronym	Meaning
FP	Fire Protection
FPRA	Fire Probabilistic Risk Assessment
FPRM	Fire Protection Requirements Manual
FSAR	Final Safety Analysis Report
FSER	Final Safety Evaluation Report
ft	feet or foot
GALL-SLR	Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report - NUREG-2191
GE	General Electric
GEH	General Electric Hitachi
GL	Generic Letter
GSI	Generic Safety Issue
HCF	High Cycle Fatigue
HCU	Hydraulic Control Unit
HELB	High Energy Line Break
HEPA	High Efficiency Particulate Air
HEU	High Enriched Uranium
HH	Handhole
HPCI	High Pressure Coolant Injection
HPFP	High Pressure Fire Protection
HVAC	Heating, Ventilation, and Air Conditioning
HVI	High Voltage Electrical Insulator
HWC	Hydrogen Water Chemistry
I&C	Instrumentation and Controls
IASCC	Irradiation Assisted Stress Corrosion Cracking
ICMH	In-Core Monitor Housing
ID	Inside Diameter
IE	Inspection and Enforcement
IEEE	Institute of Electrical and Electronics Engineers
IGSCC	Intergranular Stress Corrosion Cracking
ILRT	Integrated Leak Rate Test
IN	Information Notice
INPO	Institute of Nuclear Power Operations
IPA	Integrated Plant Assessment
ISFSI	Independent Spent Fuel Storage Installation
ISI	Inservice Inspection
ISG	Interim Staff Guidance

Acronym	Meaning
ISP	Integrated Surveillance Program
JP	Jet Pump
KSI	Kilo pounds per square inch
kV	Kilovolt
LAS	Low Alloy Steel
lbs	pounds
LCO	Limiting Condition of Operation
LERF	Large Early Release Frequency
LLRT	Local Leak Rate Test
LLRW	Low Level Radioactive Waste
LOCA	Loss-of-Coolant Accident
LPCI	Low Pressure Coolant Injection
LRA	License Renewal Application
LST	Lowest Service Temperature
LTTIP	Long-Term Torus Integrity Program
MEB	Metal Enclosed Bus
MELLLA+	Maximum Extended Load Line Limit Analysis Plus
MeV	Million Electron Volts
MH	Manhole
MIC	Microbiologically Influenced Corrosion
MoS_2	Molybdenum Disulfide
MPa	Mega-Pascal
MSIV	Main Steam Isolation Valve
MSRV	Main Steam Relief Valve
MWt	Megawatts-thermal
n/cm^2	neutrons per square centimeter
NACE	National Association of Corrosion Engineers
NBA	Nickel-Based Alloy
NDE	Non-Destructive Examination
NDT	Nil-Ductility Temperature
NDTT	Nil-Ductility Transition Temperature
NEI	Nuclear Energy Institute
NESC	National Electrical Safety Code
NFPA	National Fire Protection Association
NMCA	Noble Metals Chemical Addition
NOI	Notice of Indication

Acronym	Meaning
NPS	Nominal Pipe Size
NQAP	Nuclear Quality Assurance Plan
NRC	Nuclear Regulatory Commission
NSPC	Nuclear Safety Performance Criteria
NSR	Nonsafety-related
NSSS	Nuclear Steam Supply System
NTTF	Near Term Task Force
NUMARC	Nuclear Utility Management and Resources Council
NWC	Normal Water Chemisty
OBE	Operational Basis Earthquake
OCCW	Open-Cycle Cooling Water
OE	Operating Experience
OLNC	Online Noble Chemistry
OLTP	Original Licensed Thermal Power
PAU	Physical Analysis Unit
PEO	Period of Extended Operation
P&IDs	Piping and Instrumentation Diagrams
PM	Preventive Maintenance
PSI	Pounds per square inch
P-T Limit	Pressure-Temperature Limit
PUAR	Plant Unique Analysis Report
PVC	Polyvinyl Chloride
PWR	Pressurized Water Reactor
QA	Quality Assurance
RA	Area Reduction
RAI	Request for Additional Information
RAMA	Radiation Analysis Modeling Application
RCIC	Reactor Core Isolation Cooling
RCPB	Reactor Coolant Pressure Boundary
RCS	Reactor Coolant System
RCW	Raw Cooling Water
RFP	Reactor Feedwater Pump
RG	Regulatory Guide
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RPT	Recirculation Pump Trip

Acronym	Meaning
RT_{MAX}	Maximum Reference Temperature
RT_{NDT}	Nil-Ductility Transition Reference Temperature
RPV	Reactor Pressure Vessel
RPVII	Reactor Pressure Vessel Internals Inspection
RSD	Replacement Steam Dryer
RV	Reactor Vessel
RVI	Reactor Vessel Internals
RVID	Reactor Vessel Integrity Database
RWCU	Reactor Water Cleanup
SBO	Station Blackout
SBR	Sand Bed Region
SCC	Stress Corrosion Cracking
SDBR	Shutdown Board Room
SDG	Supplemental Diesel Generator
SE	Safety Evaluation
SEI	Structural Engineering Institute
SER	Safety Evaluation Report
SG	Steam Generator
SGTS	Standby Gas Treatment System
SJAE	Steam Jet Air Ejector
SLC	Standby Liquid Control
SLR	Subsequent License Renewal
SLRA	Subsequent License Renewal Application
SPEO	Subsequent Period of Extended Operation
SR	Safety-Related or Silicone Rubber
SRM	Source Range Monitor
SRV	Safety Relief Valve
SRP-SLR	Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants - NUREG-2192
SS	Stainless Steel
SSCs	Systems, Structures, and Components
SSE	Safe Shutdown Earthquake
SSLR	Supplemental Subsequent License Renewal
TAP	Torus Attached Piping
TLAAs	Time-Limited Aging Analyses
TRM	Tennessee River Mile

Acronym	Meaning
TS	Technical Specifications
TVA	Tennessee Valley Authority
USAS	USA Standard
USE	Upper-Shelf Energy
USST	Unit Station Service Transformer
UT	Ultrasonic (Volumetric) Test
UV	Ultraviolet
V	Volt
VFD	Variable Frequency Drive
VT	Visual Test
WANO	World Association of Nuclear Operators
WLI	Water Level Instrumentation
WO	Work Order
XLPE	Cross-Linked Polyethylene

1.7 GENERAL REFERENCES

1.7.1 10 CFR 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants”

1.7.2 NEI 95-10, Revision 6, “Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule,” June 2005

1.7.3 NEI 17-01, “Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal,” December 2017

1.7.4 Regulatory Guide 1.188, Revision 2, “Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses”

1.7.5 NUREG-2192, Revision 0, “Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants”

1.7.6 NUREG-2191, Revision 0, “Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report

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 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants”

1.7.13 10 CFR 51, “Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions”

1.7.14 NUREG-0933, “Resolution of Generic Safety Issues,” U.S. Nuclear Regulatory Commission, Supplement 35

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 in Browns Ferry Nuclear Plant (BFN) subsequent license renewal (SLR) 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 license renewal applicant to identify and list those structures and components subject to Aging Management Review (AMR). 10 CFR 54.21(a)(2) further requires that the methods used to implement the requirements of 10 CFR 54.21(a)(1) be described and justified. Section 2 of this application satisfies these requirements.

The scoping and screening 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 is the process of determining which components associated with the in scope systems and structures are subject to an aging management review in accordance with 10 CFR 54.21(a)(1) requirements. A detailed description of the BFN scoping and screening process is provided in Section 2.1.

The scoping and screening methodology is consistent with the guidelines presented in Nuclear Energy Institute (NEI) 17-01, “Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal” (Reference 1.7.3). The plant level scoping results identify the systems and structures within the scope of SLR in Section 2.2. The screening results identify components subject to aging management review as described in Section 2.3 for mechanical systems, Section 2.4 for structures and component supports, and Section 2.5 for electrical and instrumentation and control systems.

2.1 SCOPING AND SCREENING METHODOLOGY

2.1.1 Introduction

This introduction provides an overview of the scoping and screening process used at BFN. Subsequent sections provide details of how the process is implemented.

The initial step in the scoping process is to define the entire plant in terms of systems and structures. Each of these 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 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 requirement of one of the SLR regulated events. The intended function(s) that are the bases for including systems and structures within the scope of SLR are also identified.

Systems that contain mechanical components such as pumps, piping, valves, etc., are addressed as mechanical systems. A mechanical system is included within the scope of SLR if any portion of the system met the scoping criteria of 10 CFR 54.4. Mechanical systems determined to be within the scope of SLR are then further evaluated to determine those system components that are required to perform or support the identified system intended function(s).

SLR system descriptions were developed for each in scope mechanical system and are included in Section 2.3. These descriptions include relevant information from system descriptions included in the Final Safety Analysis Report (FSAR). The in scope boundaries of mechanical systems are identified. These boundaries are depicted on the subsequent license renewal boundary drawings by the use of boundary flags which identify SLR system interfaces. The in scope boundaries of the mechanical systems and in scope mechanical components are shown highlighted in red or blue. Mechanical components that are required to perform or support safety-related functions or are required to demonstrate compliance with one of the SLR regulated events are shown highlighted in red.

Nonsafety-related mechanical components that are included within the scope of SLR because they provide structural support to safety-related SSCs are shown highlighted in blue. Nonsafety-related mechanical components that are included within the scope of SLR because component failure could prevent the accomplishment of a safety-related function due to potential spatial interaction with safety-related SSCs are shown highlighted in blue. Additional details on system scoping evaluations and boundary drawing development are provided in Section 2.1.5.

A structure is included within the scope of SLR if any portion of the structure met the scoping criteria of 10 CFR 54.4. Structures are further evaluated to determine those structural components that are required to perform or support the identified structure intended function(s). SLR structure descriptions are developed for each in scope structure and are included in Section 2.4. These descriptions include relevant information from structure descriptions included in the FSAR. The structures that are within the scope of SLR are highlighted in red on the site plan. Additional details on structure scoping evaluations and boundary drawing development are provided in Section 2.1.5.

For the purposes of system level scoping, a bounding approach is used for plant electrical and instrumentation and control (I&C) systems. The electrical and I&C systems are all included in the scope of SLR. Electrical and I&C components in mechanical systems are also included in the scope of SLR. Intended functions for electrical and I&C systems are not identified since the bounding scoping approach makes it unnecessary to determine if an electrical or I&C system has an intended function. This method does not prevent elimination of commodity groups or specific plant systems from aging management review during the screening process. The 10 CFR 54.21 screening process eliminates commodities that are active, short lived, or do not perform a SLR intended function.

The one exception to this bounding approach methodology for electrical and I&C systems is to provide a scoping evaluation for components and commodities associated with providing offsite power to the plant, i.e., switchyard equipment. Scoping evaluation of this “system” is performed based on Nuclear Regulatory Commission (NRC) guidance in NUREG-2192, “Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants,” Section 2.5.2.1.1 (Reference 1.7.5). This guidance identifies that the plant system portion of the offsite power system that is used to connect the plant to the offsite power source meets scoping criteria under 10 CFR 54.4(a)(3).

After completion of the scoping and boundary evaluations, the screening process is performed to evaluate the structures and components within the scope of SLR to identify the long-lived and passive structures and components subject to an AMR. In addition, the passive intended functions of structures and components subject to AMR are identified. Additional details on the screening process are provided in Section 2.1.6.

Selected components, such as component supports, hazard barriers and elastomers, electrical and instrumentation enclosures, and passive electrical components, are 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. To support screening, passive structural commodities and passive electrical commodities are identified. Commodity groups utilized are consistent with Table 2.1-6 of NUREG-2192 (Reference 1.7.5).

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 CLB for BFN is consistent with the definition provided in 10 CFR 54.3. 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 (SERs) are available in a searchable database, such that applicable documents can be identified and located by searching the appropriate topic.

2.1.2.1 Final Safety Analysis Report

The BFN FSAR, which is updated regularly in accordance with the requirements of 10 CFR 50.71(e), provided significant input for system and structure descriptions and functions.

2.1.2.2 Safe Shutdown Analysis Calculation

The BFN Safe Shutdown Analysis calculation was used as the primary source document to identify safety-related functions for systems. This calculation is a living document that systematically describes how each system is utilized in the documented safety analysis for each applicable event and summarizes the required systems' functions for safe shutdown for transients, accidents, and special events (e.g, external events and other events of regulatory concern, such as shutdown without control rods). The Safe Shutdown Analysis calculation documents the system safety actions for which credit has been taken in the FSAR, Reload Analyses, and other licensing communications concerning transient, accident, and special events.

2.1.2.3 Environmental Qualification Documentation Packages

Environmental Qualification Documentation Packages provide a compilation of documentation that supports environmental qualification for a given BFN component or equipment type and includes requirements for maintaining qualification of that component or equipment type for the life of the plant. The list of BFN components that are within the scope of 10 CFR 50.49 is maintained as part of the BFN component database (i.e., Master Equipment List).

2.1.2.4 Design Criteria Documents

System Design Criteria Documents (DCDs) are available for selected BFN systems. DCDs provide detailed descriptions of the associated system design basis, including system functions and design requirements. The system DCDs were reviewed, when available, during the system scoping review.

2.1.2.5 Engineering Drawings

Engineering drawings at BFN provide system, structure, and component configuration details and safety classification information. These drawings were utilized to determine SSC functional requirements and materials of construction in support of scoping and screening evaluations.

2.1.2.6 Controlled Plant Component Database

BFN maintains a controlled plant component database (i.e., Master Equipment List) containing integrated design and maintenance information. The Master Equipment List is maintained within the Maximo enterprise asset management software. The plant component database lists plant components at the level of detail for which discrete maintenance or modification activities are typically performed. The database provides a comprehensive listing of plant components and their quality classifications. Unique equipment component tag numbers identify each component in the database.

2.1.2.7 NFPA 805 Fire Protection Report

The scope of the BFN Fire Protection Program is based on 10 CFR 50.48(a) and National Fire Protection Association (NFPA) 805 as referenced in 10 CFR 50.48(c). The NFPA 805 Fire Protection Report describes the fire protection configuration for the confinement, detection, and suppression of fires, and demonstrates the capability to achieve and maintain safe and stable conditions in the event of a fire, in support of the Fire Protection Program functions.

2.1.2.8 Other CLB References

- <u>NRC Safety Evaluation Reports and Safety Evaluations</u> include NRC staff review of BFN licensing submittals. Some of these documents may identify licensee commitments.
- <u>Technical Specifications</u> provide safety limits, limiting conditions for operation, and surveillance requirements applicable to SSCs whose functions are critical to safety.

- Technical Specifications Bases provide the SSC functional characteristics that underlie the Technical Specification limits and requirements.
- 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.
- Engineering evaluations and calculations can provide additional information about the requirements or characteristics associated with the evaluated systems, structures, or components.

2.1.3 Technical Basis Documents

Technical basis documents (Task Reports) are prepared in support of the BFN SLR project. These Task Reports contain technical evaluations and bases for decisions or positions associated with SLR requirements as described below. Task Reports are prepared, reviewed, and approved in accordance with controlled project procedures, and are based on the CLB source documents described in Section 2.1.2.

2.1.3.1 Subsequent License Renewal Systems and Structures List

One of the first steps necessary to begin the SLR scoping process is to identify a comprehensive list of plant systems and structures to be evaluated for SLR scoping. A Task Report was prepared to establish this list and to document the basis for the list. While the Maximo equipment database list of BFN systems and structures is the primary source for identifying plant systems and structures appropriate for SLR consideration, other sources of information were reviewed to ensure that all plant systems and structures were identified. The other resources were evaluated for additional information and insight to ensure the list of plant systems and structures is complete: the initial BFN License Renewal Application (LRA); site drawings; the structures' DCD; the BFN FSAR; the Master Equipment List and other plant design/licensing basis documents.

Once the plant systems and structures are identified, each of them is evaluated to determine how to organize them for SLR consideration. In general, plant systems align with SLR systems at BFN. For scoping, BFN does not "realign" system components. However, for screening and aging management reviews, when a plant system contains components which support the basic function of a different plant system, those components have been administratively realigned to that other system for subsequent license renewal purposes. In addition, in some cases in scope components of a system are evaluated separately in commodity groups. For example, electrical, instrumentation and control isolation components in nonsafety-related systems separating the nonsafety-related system from a safety-related system, are included in scope as electrical commodities, evaluated by the spaces approach. This approach is consistent with the NRC guidance in NUREG-2192, Section 2.2.3.1 (Reference 1.7.5).

Commodity groups are also established, during the screening process, to facilitate a focused aging management review process. These commodity groups include electrical and instrumentation enclosures, component supports, penetrations and sleeves, and other general categories which are common to many systems and structures. This allows for evaluation in one location rather than in each system or structure in which they are applicable.

Once the systems and structures are identified, BFN systems and structures were grouped into the following categories:

- Reactor Vessel, Internals, and Reactor Coolant System

- Engineered Safety Features and Reactor Core Isolation Cooling System
- Auxiliary Systems
- Steam and Power Conversion System
- Containments, Structures and Component Supports
- Electrical and I&C Systems

This grouping of the BFN systems and structures is based on BFN FSAR and the guidance of NUREG-2191, “Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report” (Reference 1.7.6). The complete list of systems and structures evaluated for SLR is provided in Table 2.2-1.

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

Those systems for which no functions are identified as satisfying any of the three scoping criteria are classified as systems outside the scope of license renewal, and no further evaluation is performed.

2.1.3.2 Identification of Safety-Related Systems and Structures

Safety-related systems and structures are included within the scope of SLR in accordance with 10 CFR 54.4(a)(1) scoping criterion. BFN plant systems and structures that have been designed to safety-related standards are identified in the FSAR. BFN plant components that have been classified as safety-related are identified as “SR” in the controlled safety classification data field in the controlled plant component database. BFN safety classification procedures are reviewed against the SLR “Safety-related” scoping criterion in 10 CFR 54.4(a)(1), to confirm that BFN safety-related classifications are consistent with SLR requirements. This review is included in a Task Report. The Task Report also provides summary lists of the systems and structures that are safety-related at BFN.

The TVA Nuclear Quality Assurance Plan definition of safety-related is as follows:

Safety-related structures, systems, and components - Those items that are necessary to ensure:

- The integrity of the reactor coolant pressure boundary.
- The capability to shut down the reactor and maintain it in a safe shutdown condition.
- The capability to prevent, or mitigate the consequences of an accident which could result in potential offsite exposures comparable to the applicable guideline exposures of 10 CFR 50.34(a)(1) or 10 CFR 100.11, as applicable.

This definition of safety-related SSCs is similar to the 10 CFR 54.4(a)(1) definition of safety-related SSCs, with the following exceptions:

Design Basis Events

The License Renewal Rule 10 CFR 54.4(a)(1) specifically refers to design basis events as defined in 10 CFR 50.49(b)(1), while the BFN definition of safety-related is applied to accidents in general terms. For the purposes of identifying SSCs within the scope of SLR, design basis events were identified using the FSAR and the Safe Shutdown Analysis Calculation, and include external hazards such as fire, earthquakes, flooding, wind and missiles, and high-energy line breaks. As such, applicable BFN Design Basis Events (DBEs), as defined in 10 CFR 50.49(b)(1), have been used for SLR scoping.

Exposure Limits

The guidelines specified in the License Renewal Rule refer to three different Code sections to address similar accident analyses performed by licensees for different reasons:
10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), and 10 CFR 100.11.

The guidelines in 10 CFR 50.34(a)(1) are applicable to facilities seeking a construction permit and are therefore not applicable to BFN.

With respect to 10 CFR 50.67(b)(2) and 10 CFR 100.11, the following discussion is provided. The FSAR Chapter 14 accident analyses were originally performed to address 10 CFR 100 guidelines. Radiological consequence analyses of the design basis accidents were performed to support a full-scope implementation of Alternative Source Term (AST) methodology in accordance with the guidance in Regulatory Guide 1.183. AST radiological consequence analyses were performed for the four BFN design basis accidents that result in offsite exposures. These four accidents are the Loss of Coolant Accident, Main Steam Line Break, Refueling Accident, and Control Rod Drop Accident. The dose consequences for these accidents result in doses that are within the guidelines of 10 CFR 50.67. On September 27, 2004, the NRC approved the BFN license amendment request regarding AST per 10 CFR 50.67(b)(2) for offsite dose exposure as the current licensing basis for BFN (ADAMS Accession No. ML042730028). As such, the AST analytical methods described in Regulatory Guide 1.183 and dose limits defined in 10 CFR 50.67 comprise the licensing basis for BFN design basis accidents. Since the definition of safety-related components as applied to the scoping of components for SLR can be either 10 CFR 50.67(b)(2) or 10 CFR 100.11, as applicable, and the AST submittal did not add new components within the SLR scope, it does not impact the definition of safety-related.

2.1.3.3 10 CFR 54.4(a)(2) Scoping Criteria

All nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of any of the functions identified in 10 CFR 54.4(a)(1), are included within the scope of SLR in accordance with 10 CFR 54.4(a)(2) requirements. To assure complete and consistent application of this scoping criterion, a Task Report was prepared.

This SLR scoping criteria requires consideration of the following:

1. Functional support - A nonsafety-related SSC that is functionally relied upon in the CLB to (a) directly support a safety-related SSC in performing its 10 CFR 54.4(a)(1) function or (b) directly mitigate the consequences of a DBE.
2. Spatial interaction - The effect(s) of nonsafety-related SSC failure on a safety-related component, such as pipe whip, jet impingement, general flooding, spray, and displacement/ falling.
3. Structural interaction - Occurs in situations where a nonsafety-related piping system physically connects to a safety-related system and the nonsafety-related system is relied upon to provide

physical support to the safety-related system up to and including the first anchor (or alternate anchor) beyond the safety-related/nonsafety-related interface.

The first item is addressed during the scoping process, by identifying the nonsafety-related systems and structures required to functionally support the accomplishment of a safety-related intended function under 10 CFR 54.4(a)(1), and then including these supporting systems and structures in scope of SLR under 10 CFR 54.4(a)(2).

The remaining two items concern nonsafety-related systems with potential physical or spatial interaction with safety-related SSCs. Scoping of these systems is the subject of NEI 95-10, Appendix F (Reference 1.7.2), as referred to in NEI 17-01 (Reference 1.7.3). To assure complete and consistent application of 10 CFR 54.4(a)(2) requirements and NEI 95-10, a Task Report was prepared. The Task Report includes a review of the CLB references relevant to physical and spatial interactions.

The Task Report describes the BFN approach to scoping of nonsafety-related systems with a potential for physical or spatial interaction with safety-related SSCs. The Task Report provides appropriate documentation to demonstrate that SLR scoping for 10 CFR 54.4(a)(2) meets the requirements of the license renewal rule and NEI 95-10. Additional detail on the application of the 10 CFR 54.4(a)(2) scoping criterion is provided in Section 2.1.5.2.

2.1.3.4 Scoping for Regulated Events

In accordance with 10 CFR 54.4(a)(3), SLR Task Reports address SLR scoping of SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for Fire Protection, Environmental Qualification, Anticipated Transient Without Scram, and Station Blackout. The NRC regulations for pressurized thermal shock are not applicable to the BFN Boiling Water Reactor (BWR) design. These Task Reports are summarized below:

<u>Fire Protection</u>

The BFN Fire Protection Program is based upon the defense in depth concept. Defense in depth is achieved by fire prevention, fire detection and mitigation, and maintaining the capability to place the nuclear fuel in a safe and stable condition should a fire occur. Systems and structures in the scope of SLR for fire protection include those required for compliance with 10 CFR 50.48(c). Equipment relied on for fire protection includes SSCs credited for fire prevention, detection, and mitigation in areas containing equipment important to safe operation of the plant and equipment necessary to place and maintain the nuclear fuel in a safe and stable condition. The Fire Protection Program is described in the FSAR Section 10.11 and the BFN NFPA 805 Fire Protection Report.

The fire protection Scoping Task Report summarizes results of a detailed review of the BFN Fire Protection Program documents that demonstrate compliance with the requirements of 10 CFR 50.48 (Reference 1.7.7). The Task Report provides a list of systems and structures credited in the BFN Fire Protection Program documents. For the listed systems and structures, the Task Report 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 BFN are plant-wide systems that protect a wide variety of plant equipment. Not all portions of these systems are required to demonstrate compliance with 10 CFR 50.48. Some portions of the fire detection and suppression systems protect plant areas in which a fire would not impact any equipment important to safety or significantly increase the risk of radioactive releases to the environment. Portions of the fire suppression and detection systems that are not included within the scope of subsequent license renewal are identified on the Fire Protection System subsequent license renewal boundary drawings in black.

Environmental Qualification

Criterion 10 CFR 54.4(a)(3) requires that all SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for Environmental Qualification (EQ) (10 CFR 50.49) be included within the scope of SLR (Reference 1.7.8).

The BFN EQ program includes 1) safety-related electrical equipment, 2) nonsafety-related electrical equipment whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions, and 3) certain post-accident monitoring equipment as defined in 10 CFR 50.49(b)(1), 10 CFR 50.49(b)(2), and 10 CFR 50.49(b)(3). This equipment is included within the scope of SLR.

All systems were compared to the list of systems that contain environmentally qualified equipment as stated in the Master Equipment List of the Maximo equipment database. All structures were compared to the structures that contain harsh environments as defined by the BFN Harsh Environmental Data Drawing Series. The EQ Scoping Task Report summarizes the results of this review. The Task Report provides a list of systems that include EQ components. The Task Report also provides a list of structures that provide the physical boundaries for the postulated harsh environments, and contain environmentally qualified electrical equipment.

These systems and structures are included within the scope of SLR in accordance with 10 CFR 54.4(a)(3) scoping criteria.

Anticipated Transient Without Scram

Criterion 10 CFR 54.4(a)(3) requires that all SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for anticipated transient without scram (10 CFR 50.62) be included within the scope of SLR (Reference 1.7.9).

An Anticipated Transient Without Scram (ATWS) is an anticipated operational occurrence that generates an automatic scram signal, accompanied by a failure of the reactor protection system to automatically shutdown the reactor. The ATWS rule (10 CFR 50.62) requires improvements in the design and operation of light-water cooled water reactors to reduce the likelihood of failure to automatically shutdown the reactor, and to mitigate the consequences of an ATWS event. BFN Units 1, 2 and 3 are BWRs.

For BWRs, the following requirements apply:

- Each BWR must have an alternate rod injection (ARI) system with redundant scram air header exhaust valves. The ARI system must be independent of the existing reactor trip system.
- Each BWR must have a standby liquid control system with defined boron injection capabilities. Standby liquid control system automatic initiation is not required for plants issued a construction permit before July 26, 1984, unless already installed. The BFN standby liquid control system is manually initiated.
- Each BWR must have equipment to trip the recirculation pumps automatically under conditions indicative of an ATWS.

The ATWS Scoping Task Report summarizes the results of a review of the BFN CLB with respect to ATWS. The BFN design features to meet the requirements of 10 CFR 50.62 for ATWS mitigation include:

- ARI system features to satisfy the requirements of 10 CFR 50.62(c)(3). The ARI system is included in the Control Rod Drive system for SLR.
- Standby Liquid Control system to meet the requirements of 10 CFR 50.62(c)(4).
- ATWS Recirculation Pump Trip (RPT) system to satisfy the requirements of 10 CFR 50.62(c)(5). The ATWS-RPT function is included in the Reactor Recirculation system for SLR.

The Task Report provides a list of the systems required by 10 CFR 50.62 to reduce the risk from ATWS events. The Task Report also provides a list of structures that provide physical support and protection for the ATWS systems. These systems and structures are included within the scope of SLR in accordance with 10 CFR 54.4(a)(3) scoping criteria.

Station Blackout

Criterion 10 CFR 54.4(a)(3) requires that all SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC regulations for station blackout (10 CFR 50.63) be included within the scope of SLR (Reference 1.7.10).

The Station Blackout (SBO) rule requires each plant to cope with the loss of off-site power concurrent with the failure of Emergency Diesel Generators (EDGs) in excess of those required for normal redundancy. For the SBO duration, the plant must be capable of maintaining core cooling and appropriate containment integrity. SBO coping duration for BFN is four hours. SBO is postulated as the failure of the two 4.16 kV EDGs that normally feed a respective unit's 480-Volt (V) Alternating Current (AC) shutdown boards concurrent with the loss of all offsite power. BFN capabilities, commitments, and analyses that demonstrate compliance with 10 CFR 50.63 are documented in FSAR Chapter 8 and in the NRC safety evaluation and correspondence related to the SBO rule.

The BFN SBO coping strategy is to shutdown the blacked-out unit with equipment powered from the 250-V Direct Current (DC) battery system. Alternate AC power from Emergency Diesel Generators (EDGs) in the non-blacked-out units, will be made available to power additional required heating, ventilation, and air conditioning (HVAC) and common loads. As set forth in Appendix B of Nuclear Utility Management and Resources Council (NUMARC) 87-00, “Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors,” dated August 1991, the Alternate AC will be available within one hour through existing cross-ties. The 250-V unit batteries 1, 2, and 3 are adequate to supply the required BFN Unit 1, Unit 2, and Unit 3 loads for the coping duration of four hours. SBO on Unit 1 is the loss of EDGs A and C and loss of EDGs B and D for SBO on Unit 2. SBO on Unit 3 is the loss of EDGs 3A and 3C. Considering the failure of one EDG in each of non-blacked out units (A or C for Unit 1, B or D for Unit 2, and 3A or 3C for Unit 3), and additional failure of EDG 3B or 3D, a minimum of three diesel generators remain available for SBO. These provide sufficient power to supply required HVAC and common loads.

The NUREG-2192 (Reference 1.7.5) guidance on scoping of equipment relied on to meet the requirements of the SBO rule (10 CFR 50.63) for SLR has been incorporated into the BFN scoping methodology. In accordance with the NUREG-2192, the SSCs required to cope with and recover from the SBO event are included within the scope of SLR.

Coping is defined as the period of time when the station’s offsite sources and on-site ac sources (i.e., EDGs) are unavailable. Coping assessments are performed for condensate inventory, Class 1E battery capacity, compressed air, loss of ventilation, and containment isolation. As stated above, BFN is a four-hour coping duration plant, and the coping analysis credits an Alternate AC source. Consistent with the first license renewal application and aligned with the SLR scoping methodology, the SBO Alternate AC source is included in the scope of SLR. The SLR boundary for the SBO Alternate AC source was established based on BFN current licensing basis.

Figures 2-1, 2-2, and 2-3 show the Alternate AC source components and the connection to BFN safety-related buses.

Recovery is defined as the repowering of the plant AC distribution system from offsite sources or onsite emergency AC sources. In alignment with the SLR scoping methodology, for BFN SBO, the boundary between the offsite transmission system and the plant electrical distribution system has been defined for each of the incoming offsite sources.

The off-site and on-site AC Electrical Power Distribution System consist of the off-site AC power sources (preferred normal and alternate power sources), and the Class 1E onsite standby AC power sources (emergency diesel generators). The Class 1E AC distribution system is divided into redundant divisions, so loss of any one division does not prevent the minimum safety functions from being performed. Each of four 4kV shutdown boards has two off-site power supplies available and a single emergency diesel generator. An off-site circuit consists of breakers, transformers, switches, interrupting devices, bus, cabling, protective relaying, and controls required to transmit power from the off-site transmission network to the 4 kV shutdown boards. Off-site power is supplied to the 161 kV and 500 kV switchyards from the transmission network by seven transmission lines (two 161 kV lines and five 500 kV lines).

The following nonsafety-related electrical systems and structures are in the scope of 10 CFR 54 because they contain components that meet the criteria of 10 CFR 54.4(a)(3) for SBO offsite power restoration:

- System 57 - Electrical Distribution System (including 500 kV/161 kV Offsite Power System, 4 kV and 480 VAC Distribution Systems)
- System 202 - 4 kV Unit Boards
- System 204 - 4 kV Unit Start Board and Bus
- System 210 - 4 kV Bus Tie Board
- System 211 - 4 kV Shutdown Boards and Buses

- System 236 - Main Transformers
- System 243 - Unit Station Service Transformer
- System 245 - Common Station Service Transformer
- System 248 - 250 VDC Power System
- System 282 - 250 VDC Distribution Boards
- Transformer Yard
- 161 kV Switchyard
- 500 kV Switchyard

The portions of the nonsafety-related plant AC electrical systems required for SBO extend:

- From the first active component in the 500 kV switchyard, through main transformer 1 and unit station service transformer 1A or 1B to a 4kV unit board. That unit board feeds 4kV shutdown bus 1 or 2, which then feeds the Unit 1 and 2 4kV shutdown boards and 4kV bus tie board, which feeds Unit 3 4kV shutdown boards.
- From the first active component in the 500 kV switchyard, through main transformer 2 and unit station service transformer 2A or 2B to a 4kV unit board. That unit board feeds 4kV shutdown bus 1 or 2, which then feeds the Unit 1 and 2 4kV shutdown boards and 4kV bus tie board, which feeds Unit 3 4kV shutdown boards.
- From the first active component in the Trinity or Athens 161 kV transmission system, through common station service transformer A or B to start bus 1A or 1B via the 4kV unit start board, then to a 4kV unit board. That unit board feeds 4kV shutdown bus 1 or 2, which then feeds the Unit 1 and 2 4kV shutdown boards and also feeds the Unit 3 4kV shutdown boards via the 4kV bus tie board.
- From the first active component in the 500 kV switchyard, through main transformer 3 and unit station service transformer 3A or 3B to 4kV unit board(s) 3A, 3B, and/or 3C. Each unit board feeds two of the Unit 3 4kV shutdown boards.

This boundary is consistent with NRC standard review plan for SLR, NUREG-2192, Section 2.5.2.1.1 (Reference 1.7.5) for the boundary for the SBO recovery path. The NUREG states that the in scope plant system portion of the offsite power system that is used to connect the offsite power source is the equipment out to the first circuit breaker with the offsite distribution system. This typically includes equipment in the switchyard with the boundary point being a component that operates at transmission system distribution voltage. Control circuits and structures associated with in scope switchyard components are included in the scope for SLR. See Figures 2-1, 2-2, and 2-3 for the BFN SBO recovery path boundary.

The SBO Scoping Task Report summarizes the results of a review of the BFN CLB with respect to SBO. The Task Report provides lists of systems and structures credited in BFN SBO evaluations. For the listed systems and structures, the Task Report also identifies appropriate CLB references. These systems and structures are included within the scope of SLR in accordance with 10 CFR 54.4(a)(3) scoping criteria.

Figure 2-1, BFN Unit 1/2 SBO Alternate AC Source and Recovery Path Boundaries

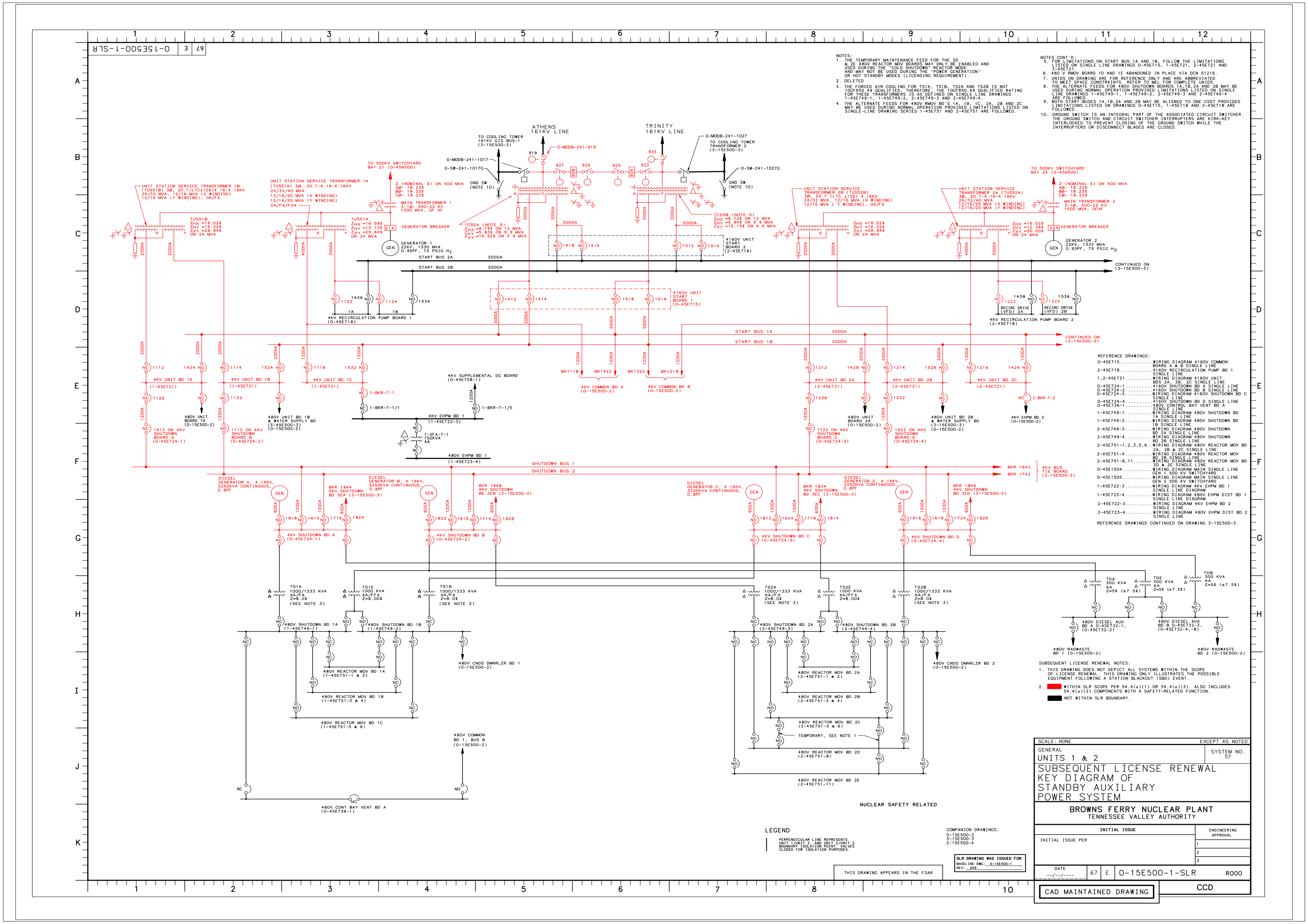


Figure 2-2, BFN Unit 1/2 SBO Alternate AC Source and Recovery Path Boundaries (continued)

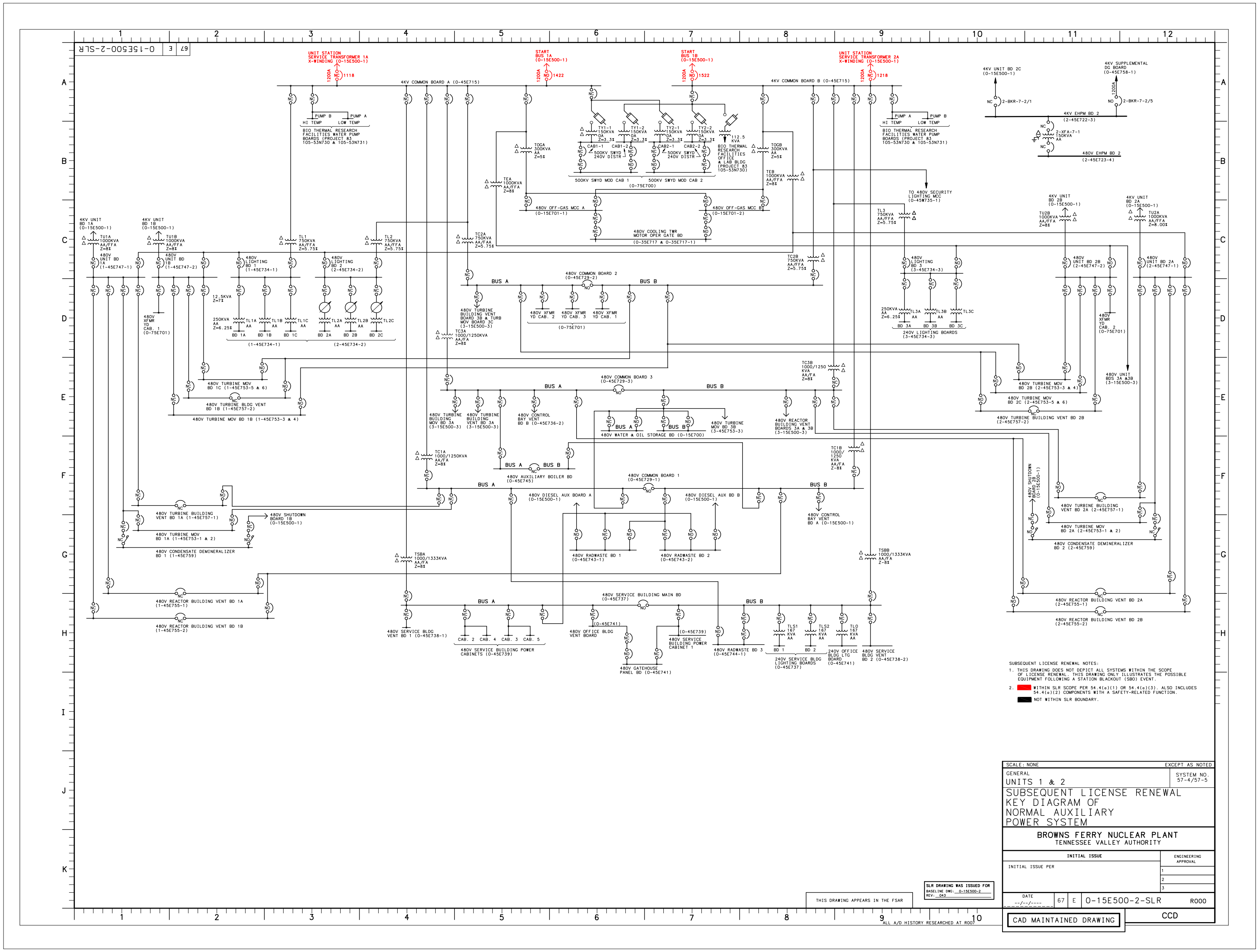
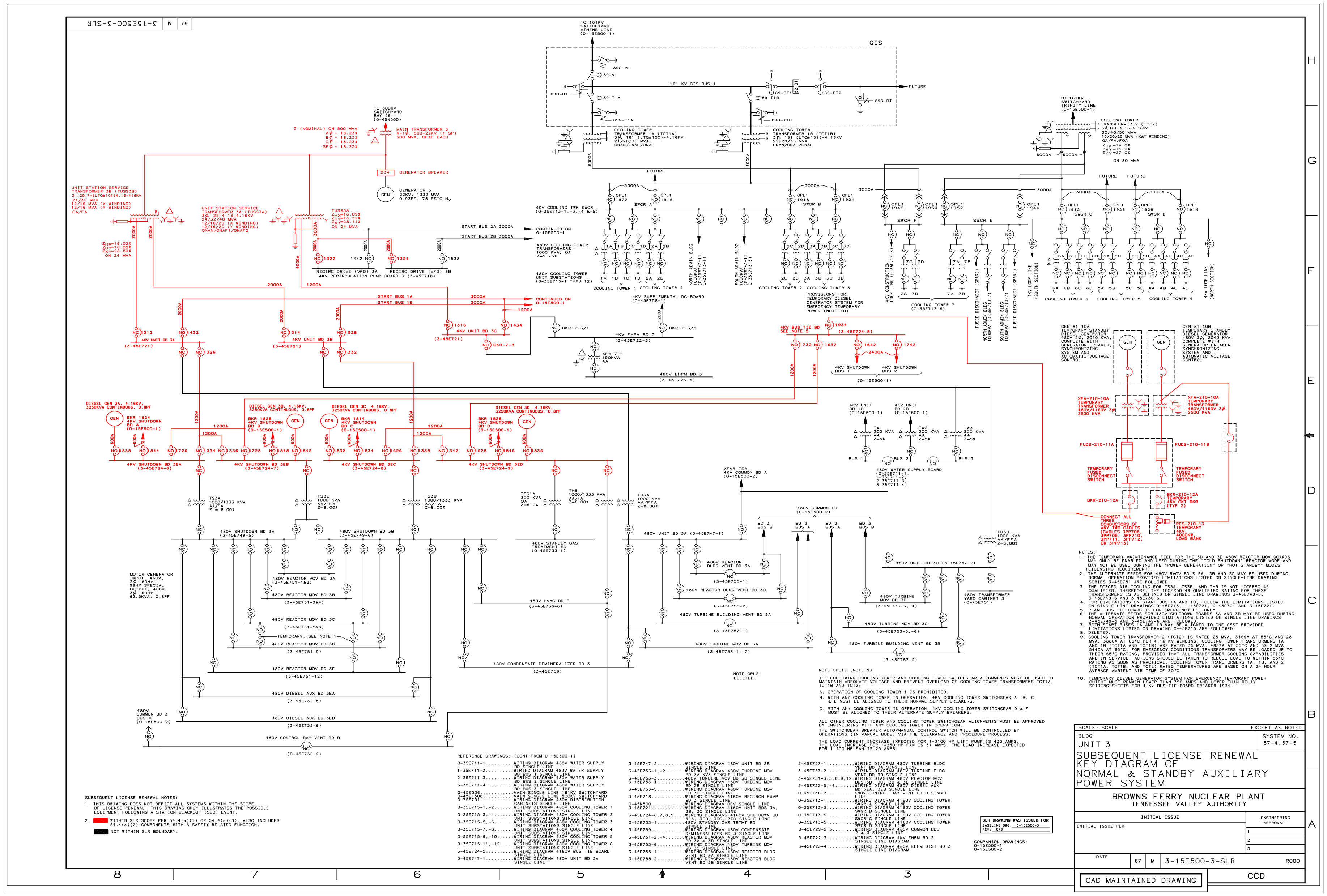


Figure 2-3, BFN Unit 3 SBO Alternate AC Source and Recovery Path Boundaries



2.1.4 Interim Staff Guidance Discussion

As discussed in NEI 17-01 (Reference 1.7.3), the NRC has encouraged applicants for SLR to address SLR Interim Staff Guidance documents (ISG) in the SLR Applications (SLRAs). Since the issuance of NUREG-2191 (Reference 1.7.6) and NUREG-2192 (Reference 1.7.5), there have been four newly issued SLR-ISGs that are currently active on the NRC website. These SLR-ISGs are as follows:

- SLR-ISG-2021-01-PWRVI, Updated Aging Management Criteria for Reactor Vessel Internal Components for Pressurized-Water Reactors, dated January 2021 (Not applicable to BWRs)
- SLR-ISG-2021-02-MECHANICAL, Updated Aging Management Criteria for Mechanical Portions of Subsequent License Renewal Guidance, Interim Staff Guidance, dated February 2021
- SLR-ISG-2021-03-STRUCTURES, Updated Aging Management Criteria for Structures Portions of Subsequent License Renewal Guidance, Interim Staff Guidance, dated February 2021
- SLR-ISG-2021-04-ELECTRICAL, Updated Aging Management Criteria for Electrical Portions of Subsequent License Renewal Guidance, Interim Staff Guidance, dated February 2021

<u>NRC Position</u>

During the reviews of the first three SLRAs that were based on NUREG-2191 and NUREG 2192, the NRC and applicants identified improvements to the guidance that would assist in preparing and reviewing future SLRAs more effectively and efficiently. The three SLR-ISGs applicable to BWRs provide interim updates to NUREG-2191 and NUREG-2192 to implement these improvements. These ISGs are not intended for standalone use. They provide revisions to NUREG-2191 and NUREG-2192 sections and tables that supersede the content in the NUREGs and are intended to be used within the context of the NUREGs. The revisions captured in these ISGs include:

- Updates to recommended Aging Management Programs (AMPs)
- Changes to AMR items in NUREG-2191 tables and corresponding summary tables in NUREG-2192
- New AMR items in NUREG-2191 tables and corresponding summary tables in NUREG-2192
- Changes to "further evaluation" guidance sections in NUREG-2192
- Updates to references listed in affected NUREG-2191 sections
- Editorial corrections to relevant sections

<u>BFN Position</u>

The BFN SLRA is developed considering the updates to NUREG-2191 and NUREG 2192, provided by the three applicable SLR-ISGs.

2.1.5 Scoping Procedure

The scoping process is the systematic approach used to identify the BFN SSCs within the scope of SLR. The scoping process is initially performed at the system and structure level, in accordance with the scoping criteria identified in 10 CFR 54.4(a). System and structure functions and intended functions are identified from a review of the source CLB documents and the first LRA. In scope boundaries are established and documented in the subsequent license renewal boundary drawings, 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 2.1.6. The system and structure scoping results are provided in Section 2.2.

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

- Reactor Vessel, Internals, and Reactor Coolant System
- Engineered Safety Features and Reactor Core Isolation Cooling System
- Auxiliary Systems
- Steam and Power Conversion System
- Containments, Structures and Component Supports
- Electrical and I&C Systems

Each system and structure is then scoped for SLR using the criteria of 10 CFR 54.4(a). These criteria are briefly identified as follows:

- Title 10 CFR 54.4(a)(1) - Safety-Related
- Title 10 CFR 54.4(a)(2) - Nonsafety-Related affecting safety-related
- Title 10 CFR 54.4(a)(3) - Regulated Events:
  - Fire Protection (10 CFR 50.48)
  - Environmental Qualification, EQ (10 CFR 50.49)
  - Pressurized Thermal Shock (10 CFR 50.61) (PWRs only)
  - Anticipated Transient Without Scram, ATWS (10 CFR 50.62)
  - Station Blackout, SBO (10 CFR 50.63)

The application of each of these criteria is discussed in Section 2.1.5.1, Section 2.1.5.2, and Section 2.1.5.3 below and the results of application of each of these criteria are provided in Table 2.2-1, Plant Level Scoping Results.

2.1.5.1 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 SLR 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 -

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

At BFN, the safety-related plant components are identified in controlled engineering drawings, calculations, and in the Maximo equipment database. The safety-related classifications in the BFN Maximo equipment database were populated using a controlled procedure with classification criteria consistent with the above 10 CFR 54.4(a)(1) criteria.

Safety-related classifications for systems and structures are based on system and structure descriptions and analyses in the FSAR, or on design basis documents such as engineering drawings, design specifications, evaluations, or calculations. Systems and structures that are identified as safety-related in the FSAR or in design basis documents are classified as satisfying the criteria of 10 CFR 54.4(a)(1) and are included within the scope of SLR. Safety-related components listed in the Maximo equipment database are reviewed and the system or structure associated with the safety-related component is included within the scope of SLR in accordance with 10 CFR 54.4(a)(1) criteria. The review also confirms that Abnormal Operating Transients (AOTs), Design Basis Accidents (DBAs), External Hazards, Internal Events, and Special Events as described in the CLB, are considered for SLR.

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

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

- All nonsafety-related SSCs 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

These three categories are discussed below:

<u>Functional Support for Safety-Related SSC 10 CFR 54.4(a)(1) Functions</u>

This category addresses nonsafety-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 are included within the scope of SLR to functionally 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 red.

The FSAR and other CLB documents are reviewed to identify nonsafety-related systems required to support satisfactory accomplishment of a safety-related function. Nonsafety-related systems credited in CLB documents to support a safety-related function are included within the scope of SLR. BFN classifies systems that are required to perform or support a safety-related function as safety-related, with the following exceptions:

- Main Steam Alternate Leak Path; Secondary Containment; Standby Liquid Control (Post-Loss of Coolant Accident (LOCA) suppression pool pH control); and Carbon Dioxide (CO_2) Fire Protection (Prevent spurious actuation)

These nonsafety-related systems, or nonsafety-related portions of safety-related systems, are included within the scope of SLR in accordance with 10 CFR 54.4(a)(2) and are identified on the subsequent license renewal boundary drawings in red.

As an additional confirmation of scoping to meet 10 CFR 54.4(a)(2) criteria, a supporting system review is completed as part of the scoping process. The scoping process is performed on a system basis. For systems included within the scope of SLR 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. Except as identified above, the BFN systems required to support 10 CFR 54.4(a)(1) functions are classified safety-related, and as such included within the scope of SLR in accordance with 10 CFR 54.4(a)(1). The identification of supporting systems is 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 (Reference 1.7.2), as referred to in NEI 17-01 (Reference 1.7.3). The guidance requires that, when demonstrating that 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 provide support for safety-related SSCs, and those that are not directly connected to safety-related systems and have the potential for spatial interactions with safety-related SSCs. The methodology as described below for the identification of BFN SSCs that satisfy the 10 CFR 54.4(a)(2) scoping criterion is based on a review of applicable CLB documents, as well as plant-specific and industry operating experience.

<u>Connected to and Provide Structural Support for Safety-Related SSCs</u>

For nonsafety-related SSCs directly connected to safety-related SSCs the nonsafety-related piping and supports, up to and including the first seismic or equivalent anchor (as described in (a) through (g) below) beyond the safety-related/nonsafety-related interface, are within the scope of SLR per 10 CFR 54.4(a)(2). The “first seismic or equivalent anchor” is defined such that the failure in the nonsafety-related pipe run beyond the first seismic or equivalent anchor will not render the safety-related portion of the piping unable to perform its intended function under CLB design conditions.

An alternative to specifically identifying a seismic anchor or equivalent anchor that supports the safety-related/nonsafety-related piping interface is to include enough of the nonsafety-related piping run to ensure these anchors are included and thereby ensure the piping and anchor intended functions are maintained. The intended function consists of two facets 1) providing structural support for the safety-related/nonsafety-related interface and 2) ensuring nonsafety-related piping loads are not transferred through the safety-related/nonsafety-related interface. In accordance with NEI 95-10, Appendix F, as referred to in NEI 17-01, the following methods a. through g. were considered to define end points for the portion of nonsafety-related piping attached to safety-related piping to be included in the scope of SLR. In these cases the nonsafety-related piping was included in scope for 10 CFR 54.4(a)(2) up to one of the following:

a. A combination of restraints or supports that encompasses at least two (2) supports in each of three (3) orthogonal directions.
b. 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 SLR scope

includes the base-mounted component as it has a support function for the safety-related piping.

c. A flexible connection that is considered a pipe stress analysis model end point when the flexible connection effectively decouples the piping system (i.e. does not support loads or transfer loads across it to connecting piping).
d. A free end of nonsafety-related piping, such as a drain pipe that ends at an open floor drain.
e. For nonsafety-related piping runs that are connected at both ends to safety-related piping, the entire run of nonsafety-related piping is included in scope.
f. A point where buried piping exits the ground. The buried portion of the piping would be included in the scope of SLR, unless a determination that the buried piping is well founded on compacted soil that is not susceptible to liquefaction is documented.
g. 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 CLB, because significantly smaller piping does not impose significant loads on larger piping and has a negligible role in supporting larger piping. The moment of inertia ratio used is 25 to 1.

These scoping boundaries were determined from review of the physical installation details, design drawings, or seismic analysis calculations.

Failure in the 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 SLR are identified on the subsequent license renewal boundary drawings in blue.

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 evaluated for SLR scope in accordance with 10 CFR 54.4(a)(2) requirements. 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. Plant walkdowns are performed, as required, to confirm that all structures containing safety-related SSCs are identified.

As described in NEI 95-10, Appendix F, as referred to in NEI 17-01, there are two options when performing this scoping evaluation: a mitigative option and a preventive option.

Mitigative Option: The mitigative option involves crediting plant mitigative features to protect safety-related SSCs from failures of nonsafety-related SSCs. Plant mitigative features considered include pipe whip restraints, jet impingement shields, spray and drip shields, seismic supports, flood barriers, and physical barriers (e.g., floors, walls, doors, conduit). 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 SLR. The mitigative option is used for scoping systems located in the Turbine Building, Intake Pumping Station, and Ventilation Vaults. The mitigative features are included in the scope of SLR.

Preventive Option: 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; the spatial relationship between safety-related and nonsafety-related SSCs within the scope of SLR will be identified without consideration of plant mitigative features. The preventive option is used for scoping systems located in the Reactor Building, Primary Containment Structures, Diesel Generator Building, Intake Pumping Station, Reinforced Concrete Chimney, Standby Gas Treatment Building, Vacuum Pipe Building, Turbine Building, Ventilation Vaults, Residual Heat Removal Service Water Tunnel, Electrical Cable Tunnel, Underground Concrete Encased Structure, and Radwaste Building.

Nonsafety-related piping and components that contain water, oil, or steam, and are located inside structures that contain safety-related SSCs, are included in scope for potential spatial interaction under criterion 10 CFR 54.4(a)(2), unless they are located in an area where there is no concern with spatial interaction due to crediting plant mitigative features. High-energy lines (normal operating service conditions above 200 degrees F and above 275 psig) with potential spatial interaction are included in the scope of SLR under 10 CFR 54.4(a)(1) or (a)(2) depending on their safety classification. Safety-related high-energy lines are in scope under 10 CFR 54.4(a)(1), and nonsafety-related high-energy lines are in scope under 10 CFR 54.4(a)(2). Potential spatial interaction due to leakage or spray is assumed for moderate/low-energy liquid systems (normal operating service conditions less than or equal to 200 degrees F or less than or equal to 275 psig) for system pressure as low as atmospheric.

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. BFN 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 function. As described in NEI 95-10, Appendix F, paragraph 5.2.2.2.2 for moderate/low energy liquid systems, physical impact from pipe whip or jet impingement do not occur and need not be considered. This same conclusion can be applied to systems containing air or gas. Thus, the nonsafety-related systems containing air or gas need not be included in the scope of SLR for spatial interaction.

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

Scoping of Abandoned Equipment

Abandoned equipment is not included within the scope of SLR if it has been confirmed to be isolated (cut/capped), vented, and drained. If this confirmation cannot be made, the system or portions thereof, are included within the scope of SLR for aging management if there is the potential for 10 CFR 54.4(a)(2) spatial or structural interaction. Abandoned equipment is not relied on to perform any function delineated in 10 CFR 54.4(a)(1) or (a)(3) as it is nonoperational. However, failure of abandoned equipment could potentially impact the performance of the safety-related function of surrounding equipment if the abandoned equipment contains water, steam, or oil. If the abandoned equipment excluded from scope has been vented, fluids drained, and isolated (cut/capped), this equipment does not perform a 10 CFR 54.4(a)(2) intended function for SLR. In addition, disconnection of wiring for power, control, or parameter indication and air supplies is not necessary to assure that the abandoned equipment has no potential spatial interaction with surrounding equipment.

2.1.5.3 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 SLR 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 transient without scram (10 CFR 50.62), and station blackout (10 CFR 50.63).

The regulation for pressurized thermal shock (10 CFR 50.61) is applicable to pressurized water reactors only, and therefore not applicable to BFN which are BWRs. For each of the other four regulations, scoping task reports are developed. Each of the regulated event scoping task reports identify the systems and structures that are relied upon to demonstrate compliance with the applicable regulation. The task reports also identify the source documentation used for the scoping determination. Systems and structures credited in the regulated events are classified as satisfying criteria of 10 CFR 54.4(a)(3) and are included within the scope of SLR.

2.1.5.4 System and Structure Intended Functions

For the systems and structures within the scope of SLR, the intended functions that are the bases for including them within the scope of SLR are identified and documented in the associated scoping task reports. The system or structure intended functions are based on the applicable CLB reference documents. For systems, the system level intended function descriptions are based on the information obtained from the BFN FSAR, Safe Shutdown Analysis calculation, and other applicable design/licensing basis documents. 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 2.1.6.2.

2.1.5.5 Scoping Boundary Determination

Systems and structures that are included within the scope of SLR are further evaluated to determine the population of in scope structures and components. This part of the process is also a transition from the scoping process to the screening process. The process for evaluating mechanical systems is different from the process for structures, primarily because the plant design document formats are different. Mechanical systems are depicted primarily on the system piping and instrumentation diagrams (P&IDs) that show the system components and their functional relationships, while structures are depicted on physical drawings. Electrical and I&C components of in scope electrical, I&C, and 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.

2.1.6 Screening Procedure

Once the SSCs within the scope of SLR are determined, the next step is to determine which structures and components are subject to an AMR.

2.1.6.1 Identification of Structures and Components Subject to AMR

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

> Each application must contain the following information:
>
> (a) An integrated plant assessment (IPA). The IPA must –
>
> (1) For those systems, structures, and components within the scope of this part, as delineated in §54.4, identify and list those structures and components subject to an aging management review. Structures and components subject to an aging management review shall encompass those structures and components –
>
> (i) That perform an intended function, as described in §54.4, without moving parts or without a change in configuration or properties. These structures and components include, but are not limited to, the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment hatches, seismic Category I structures, electrical cables and connections, cable trays, and electrical cabinets, excluding, but not limited to, pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies; and
>
> (ii) That are not subject to replacement based on a qualified life or specified time period.

Structures and components that perform an intended function without moving parts or without a change in configuration or properties are defined as passive for SLR. 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 SLR. The screening procedure is the process used to identify the passive, long-lived structures and components within the scope of SLR that are subject to aging management review.

NUREG-2192 (Reference 1.7.5) and NEI 95-10, Appendix B (Reference 1.7.2), as referred to in NEI 17-01 (Reference 1.7.3), were used as the basis for the identification of passive structures and components. Most passive structures and components are long-lived. In the few cases where a passive component is determined not to be long-lived, such determination is documented in the screening evaluation.

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

<u>Mechanical Systems</u>

The mechanical system screening process begins with the results from the scoping process. For in scope mechanical systems, the completed scoping task reports include written descriptions and specify the system's intended function. Based on this information, the system piping and instrumentation diagrams are marked up to clearly identify the in scope system boundary for

SLR. The marked up system piping and instrumentation diagrams are called subsequent license renewal boundary drawings. These system boundary drawings are reviewed to identify the passive, long-lived components and component types. Component listings from the Maximo equipment database are also reviewed to confirm that all system components are considered. In cases where the system piping and instrumentation diagram does not provide sufficient detail, such as for some large vendor supplied components (e.g., compressors, EDGs), the associated component drawings or vendor manuals are also reviewed. Plant walkdowns are performed when required for confirmation.

Some mechanical components, when combined, are considered a complex assembly. 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. An example of a complex assembly are the EDGs. 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 AMR. This follows the screening methodology for complex assemblies as described in Table 2.1-2 of NUREG-2192.

Mechanical components are screened with the system in which they were scoped. For heat exchangers, the process side of the heat exchanger is evaluated with the process side system for aging management review. Likewise, the cooling water side of the heat exchanger is evaluated with the cooling water side system for aging management review.

Structures

The structure screening process also begins with the results from the scoping process. For in scope structures, the completed scoping task reports include written descriptions of the structure and specify the structure's intended function.The associated structure drawings are reviewed to identify the passive, long-lived structures and components, structure types, and component types.

Electrical and I&C Commodities

Screening of electrical and I&C components within the in scope electrical, I&C, and mechanical systems uses a bounding approach as described in NEI 17-01 (Reference 1.7.3). Electrical and I&C components for the in scope systems are assigned to commodity groups. The commodities subject to an aging management review are identified by applying the criteria of 10 CFR 54.21(a)(1). 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 and commodities are active.

Electrical and I&C components such as resistance temperature detectors, sensors, thermocouples, and transducers as well as electric heaters primarily serve an electrical function; however, they can also serve a mechanical pressure boundary function. According to Appendix B of NEI 95-10 (Reference 1.7.2), as referred to in NEI 17-01 (Reference 1.7.3), the electrical portions of these components are active per 10 CFR 54.21(a)(1)(i) and are therefore not subject to aging management review. Only the pressure boundary of such an in scope component is subject to aging management review.

The sequence of steps and special considerations for identification of electrical commodities that require an AMR is as follows:

- Electrical and I&C components and commodities in systems within the scope of SLR at BFN are identified and listed. The listing provided by NUREG-2192, Table 2.1-6 (Reference 1.7.5), is the basis for this list. Electrical and I&C components and commodities are organized into groups such as circuit breakers, switches, and cables. Individual specific components are not identified. The electrical commodities are identified from a review of plant documents, controlled drawings, equipment databases, and interface with the parallel mechanical screening efforts.
- Following the identification of the electrical commodities, the criterion of 10 CFR 54.21(a)(1)(i) is applied to identify commodities that perform their functions without moving parts or without a change in configuration or properties (referred to as “passive” components). These commodities are identified utilizing the guidance of NUREG-2192, Table 2.1-6.
- The passive electrical commodities are reviewed to determine if the commodity performs a SLR intended function. If an electrical commodity does not perform a SLR intended function, it is not considered further and, therefore, is not subject to an AMR.
- The screening criterion found in 10 CFR 54.21(a)(1)(ii) excludes those commodities that are subject to replacement based on a qualified life or specific time period from the requirements of an AMR. The 10 CFR 54.21(a)(1)(ii) screening criterion is applied to those commodities that are not previously eliminated by the application of the 10 CFR 54.21(a)(1)(i) screening criterion. Components and commodities included in the plant EQ program are replaced on a specified interval based on a qualified life. Components and commodities in the EQ program do not meet the “long-lived” criterion of 10 CFR 54.21(a)(1)(ii) and are considered “short-lived” per the regulatory definition and are, therefore, not subject to an AMR.
- Components and commodities which support or interface with electrical components and commodities, for example, cable trays, conduits, instrument racks, panels and enclosures, are evaluated as structural components.

The passive commodities that are not subject to replacement based on a qualified life or specified time period are subject to an AMR. For BFN, the electrical commodities that require an AMR are identified in the Electrical and I&C Screening/Aging Management Review Task Report.

2.1.6.2 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 SLR. 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. BFN has considered multiple intended functions where applicable, consistent with the staff guidance provided in Table 2.1-3 of NUREG-2192 (Reference 1.7.5).

Table 2.1-1 provides definitions of structure and component passive intended functions identified in the Screening/Aging Management Review Task Reports.

Table 2.1-1, Passive Structure and Component Intended Function Definitions

Function	Definition
Absorb Neutrons	Absorb neutrons.
Direct Flow	Provide spray shield or curbs for directing flow.
Electrical Continuity	Provide electrical connections to specified sections of an electrical circuit to deliver voltage, current, or signals.
Expansion/Separation	Provide for thermal expansion and/or seismic separation.
Filter	Provide filtration or foreign material exclusion.
Fire Barrier	Provide rated fire barrier to confine or retard fire from spreading to or from adjacent areas of the plant.
Fission Product Barrier	Provide barrier to fission products release.
Flood Barrier	Provide flood protection barrier (internal or external flood event).
Flood Protection	Provide protection from internal or external flooding events.
Flow Restriction	Provide restriction/throttling.
Gaseous Release Path	Provide path for release of filtered and unfiltered gaseous discharge
Heat Transfer	Provide heat transfer.
High Energy Line Break (HELB) Shielding	Provide shielding against HELB.
Holdup and Plateout	Provide post-accident containment, plateout of iodine and holdup (for radioactive decay) of iodine and non-condensable gases.
Insulate (Electrical)	Insulate and support an electric conductor.
Maintain Adhesion	Provide adhesion to the substrate.
Mechanical Closure	Provide closure of components.
Missile Barrier	Provide missile barrier (internal or external missiles).
Pipe Whip Restraint	Provide pipe whip restraint.
Pressure Boundary	Provide pressure-retaining boundary so that sufficient flow at adequate pressure is delivered, or provide fission product barrier for containment pressure boundary, or provide containment isolation for fission product retention.
Shelter and Protection	Provide shelter/protection to components.
Shelter and Support	Provide shelter/support to components.
Shielding	Provide shielding against radiation.
Spray	Convert fluid into spray.
Structural Integrity	Component that maintains mechanical and structural integrity to provide structural support to attached piping.

Table 2.1-1, Passive Structure and Component Intended Function Definitions (Continued)

Function	Definition
Structural Support	Provide structural support and/or functional support for components.
Structural Support to Maintain Core Configuration and Flow Distribution	Provide structural support of fuel assemblies, control rods, and incore instrumentation to maintain core configuration and flow distribution.
Thermal Insulation	Inhibit/prevent heat transfer across a thermal gradient.
Thermal Insulation Jacket Integrity	Provide moisture absorption and provide physical support of thermal insulation.
Throttle	Provide flow restriction.
Water Retaining Boundary	Provide an essentially leak-tight boundary.

2.1.6.3 Stored Equipment

Credit is taken for actions required to recover certain equipment which has failed as a result of fire-induced damage. In all cases, such credit is taken only to accomplish a function required to establish and maintain safe and stable conditions. Equipment that is stored on site for installation or use in achieving safe and stable condition in the event of a fire is considered to be within the scope of SLR. For each recovery action credited, a procedure has been written and is available to cover the recovery action, and, the quantity and specific type of materials required by the analysis and the procedure are stored onsite. Stored equipment may also be used as directed by emergency operating procedures. Periodic surveillances are performed to verify that the equipment and materials are at the designated location, in the quantity specified, and in good condition and capable of performing the intended function. Tools and supplies used to place the stored equipment in service are not within the scope of SLR.

2.1.6.4 Consumables

The evaluation process for consumables is consistent with the guidance provided in NUREG-2192, Table 2.1-3 (Reference 1.7.5). Consumables are divided into the following four groups for the purpose of SLR: (a) packing, gaskets, component seals, and O-rings; (b) structural sealants; (c) oil, grease, and component 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, BFN routinely conducts tours/ walkdowns 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.

Group (b) structural sealants: AMRs are required for structural sealants in structures within the scope of SLR. 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 SLR. Therefore, these subcomponents are not subject to an AMR.

Group (d) consumables (system filters, fire extinguishers, fire hoses, and air packs): System ventilation 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 SLR, but are not subject to aging management because they are replaced based on condition. These components are periodically inspected in accordance with NFPA 10 for portable fire extinguishers, American National Standards Institute (ANSI) Z88.2-1980 for self-contained breathing air packs, and NFPA 1962 for fire hoses. These require replacement of equipment based on their condition or performance during testing and inspection. The periodic inspections are implemented by controlled BFN procedures. These components are subject to replacement based on requirements implemented by controlled procedures, and are therefore not long-lived and not subject to an aging management review.

2.1.7 Generic Safety Issues

In accordance with the guidance in NEI 17-01 (Reference 1.7.3) and Appendix A.3 of NUREG-2192 (Reference 1.7.5), review of NRC generic safety issues (GSIs) as part of the SLR process is required to satisfy 10 CFR 54.29.This guidance suggests that GSIs involving issues related to SLR AMRs or TLAAs should be addressed in the SLR. Based on NEI and NRC guidance, NUREG-0933 “Resolution of Generic Safety Issues,” Supplement 35 (Reference 1.7.14), and more recent Generic Issue Management Control System Reports, the following GSIs were reviewed to assure they did not involve aging effects for structures and components subject to an AMR or TLAA 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 TLAAs, including typical crane-related TLAAs such as cyclic loading analyses. This issue is now closed. (ADAMS Accession No. ML120940306)
- GSI-189, Susceptibility of Ice Condenser and Mark III Containments to Early Failure from Hydrogen Combustion During a Severe Accident - This issue is not applicable to BFN. BFN Units 1, 2, and 3 do not have Ice Condenser or Mark III Containments. BFN Units 1, 2, and 3, have Mark I Primary Containments. This issue is now closed. (ADAMS Accession No. ML13190A254)
- GSI-191, Assessment of Debris Accumulation on PWR Sump Performance - This issue is not applicable to BFN. BFN Units 1, 2, and 2, are BWRs.
- GSI-193, BWR ECCS Suction Concerns - The Generic Issues Review Panel completed an assessment and found this issue does not present a significant safety hazard. No further regulatory actions are required. This issue is now closed. (ADAMS Accession No. ML16207A507)
- GSI-199, Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States for Existing Plants - 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 TLAAs. Activities associated with this issue are covered by 10 CFR 50.54(f) Japan Near Term Task Force (NTTF) Recommendations. (ADAMS Accession No. ML13190A254)

In a letter dated September 24, 2020, the NRC documented the results of their review of the BFN Seismic Probabilistic Risk Assessment associated with Reevaluated Seismic Hazard Implementation of the NTTF Recommendation 2.1: Seismic. The NRC concluded that no further response or regulatory action associated with the NTTF recommendation was required. (ADAMS Accession No. ML20255A000)

- 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 TLAAs. Activities associated with this issue are covered by 10 CFR 50.54(f) Japan NTTF Recommendations. (ADAMS Accession No. ML13190A254)

  In a letter dated May 6, 2020, the NRC documented the results of their review of the BFN Flooding Focused Evaluation. The NRC concluded that, if implemented as described, BFN has effective flood protection for the beyond-design-basis local intense precipitation flood-causing mechanism. The NRC letter also documented the close-out of the BFN response for the reevaluated flooding hazard portion of the 10 CFR 50.54(f) letter. (ADAMS Accession No. ML20112F485)

Therefore, there are no GSIs involving issues related to AMRs or TLAAs that need to be addressed as part of the BFN SLRA.

2.1.8 Conclusion

The scoping and screening methodology described above was used for the BFN IPA to identify the SSCs that are within the scope of SLR and that are subject to an AMR. The methodology is consistent with and satisfies 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 Browns Ferry Nuclear Plant (BFN) systems, structures and commodity groups that were evaluated to determine if they were within the scope of subsequent license renewal, using the methodology described in Section 2.1. A reference to the section of the application that contains the scoping and screening results is provided for each in-scope system, structure and commodity group in the Table.

Table 2.2-1, Plant Level Scoping Results

System, Structure, or Commodity Group	In Scope for SLR [a]	Reference
Reactor Vessel, Reactor Vessel Internals, and Reactor Coolant System		
Reactor Vessel	Yes - SR, ATWS, FP, SBO	Section 2.3.1.1
Reactor Vessel Internals	Yes - SR, NSR, ATWS, FP	Section 2.3.1.2
Reactor Vessel Vents and Drains System	Yes - SR, NSR, ATWS, SBO	Section 2.3.1.3
Reactor Recirculation System	Yes - SR, NSR, ATWS, EQ, FP	Section 2.3.1.4
Fuel Assemblies	Yes - SR	Section 2.3.1.5
Engineered Safety Features and Reactor Core Isolation Cooling Systems		
Primary Containment Integrity	Yes - SR, EQ, FP, SBO	Section 2.3.2.1
Reactor/Refuel Zone Ventilation System	Yes - SR, NSR, EQ, FP	Section 2.3.2.1
Secondary Containment	Yes - SR, EQ, FP	Section 2.3.2.1
Primary Containment Isolation	Yes - SR, ATWS, EQ, FP, SBO	Section 2.3.2.1
Standby Gas Treatment System	Yes - SR, EQ, FP	Section 2.3.2.2
Reactor Core Isolation Cooling System	Yes - SR, NSR, ATWS, EQ, FP, SBO	Section 2.3.2.3
High Pressure Coolant Injection System	Yes - SR, NSR, ATWS, EQ, FP, SBO	Section 2.3.2.4
Residual Heat Removal System	Yes - SR, NSR, ATWS, EQ, FP	Section 2.3.2.5
Core Spray System	Yes - SR, NSR, ATWS, EQ, FP	Section 2.3.2.6
Containment Atmosphere Dilution (CAD) System	Yes - SR, NSR, EQ, FP, SBO	Section 2.3.2.7
Auxiliary Systems		
Hydrogen Injection System	No	None
Emergency High Pressure Makeup System	Yes - FP	Section 2.3.3.1
Auxiliary Boiler System	Yes - NSR	Section 2.3.3.2
Fuel Oil System	Yes - SR, NSR, FP, SBO	Section 2.3.3.3
Lubricating Oil Transfer System	No	None

Table 2.2-1, Plant Level Scoping Results (Continued)

System, Structure, or Commodity Group	In Scope for SLR [a]	Reference
Residual Heat Removal Service Water (RHRSW) System	Yes - SR, NSR, EQ, FP, SBO	Section 2.3.3.4
Raw Cooling Water System	Yes - SR, NSR, FP	Section 2.3.3.5
Raw Service Water System	Yes - NSR, FP	Section 2.3.3.6
High Pressure Fire Protection (Diesel Driven Pump) System	Yes - SR, NSR, FP	Section 2.3.3.7
Water Treatment System	No	None
Potable Water System	Yes - NSR	Section 2.3.3.8
Normal Ventilation System	Yes - SR, FP	Section 2.3.3.9
Air Conditioning System	Yes - SR, NSR, EQ, FP, SBO	Section 2.3.3.10
Control Air System	Yes - SR, NSR, EQ, FP, SBO	Section 2.3.3.11
Service Air System	Yes - NSR, FP	Section 2.3.3.12
Vacuum Priming System	No	None
Feedwater Secondary Treatment System	No	None
Insulating Oil System	No	None
CO_2 Storage, Fire Protection/ Purging System	Yes - NSR, FP	Section 2.3.3.13
Station Drainage	Yes - NSR, FP	Section 2.3.3.14
Halon Fire Protection System	No	None
Chemical Cleaning System	No	None
Sampling and Water Quality System	Yes - SR, NSR, ATWS, EQ	Section 2.3.3.15
Building Heating System	Yes - NSR, FP	Section 2.3.3.16
Breathing Air System	No	None
Hypochlorite System	Yes - SR, NSR	Section 2.3.3.17
Raw Water Chlorination System	No	None
Demineralizer Backwash Air System	Yes - NSR	Section 2.3.3.18
Standby Liquid Control System	Yes - SR, NSR, ATWS, FP	Section 2.3.3.19
Off-Gas System	Yes - SR, NSR, FP	Section 2.3.3.20
Emergency Equipment Cooling Water System	Yes - SR, NSR, EQ, FP, SBO	Section 2.3.3.21
Reactor Water Cleanup System	Yes - SR, NSR, ATWS, EQ, FP	Section 2.3.3.22
Reactor Building Closed Cooling Water System	Yes - SR, NSR, EQ, FP	Section 2.3.3.23

Table 2.2-1, Plant Level Scoping Results (Continued)

System, Structure, or Commodity Group	In Scope for SLR [a]	Reference
Auxiliary Decay Heat Removal System	Yes - SR, NSR	Section 2.3.3.24
Containment Inerting System	Yes - SR, NSR, EQ, FP	Section 2.3.3.25
Radwaste System	Yes - SR, NSR, EQ, FP	Section 2.3.3.26
Spent Fuel Pool Cooling/ Cleanup System	Yes - SR, NSR, FP	Section 2.3.3.27
Fuel Handling and Storage System	Yes - SR, NSR	Section 2.3.3.28
Primary Containment Cooling System	No	None
Standby Diesel Generators	Yes - SR, NSR, EQ, FP, SBO	Section 2.3.3.29
Supplemental Diesel Generator	Yes - FP	Section 2.3.3.30
Control Rod Drive System	Yes - SR, NSR, ATWS, EQ, FP	Section 2.3.3.31
Diesel Generator Starting Air System	Yes - SR, NSR, FP, SBO	Section 2.3.3.32
Agriculture Waste Heat Supply System	No	None
Cranes and Hoists	Yes - NSR, FP	Section 2.3.3.33
Shop Equipment	No	None
Sewage System	Yes - FP	Section 2.3.3.34
Elevator System	No	None
Turbine Building Ventilation System	Yes - FP	Section 2.3.3.9
Radwaste Building Ventilation System	Yes - SR, NSR, FP	Section 2.3.3.9
Diesel Generator Room Ventilation System	Yes - SR, FP, SBO	Section 2.3.3.9
Diverse and Flexible Coping Strategies (FLEX) System	Yes - SR, NSR	Section 2.3.3.35
Security System	Yes - FP, SBO	Section 2.3.3.36
Radiation Monitoring System (mechanical components)	Yes - SR, NSR, EQ	Section 2.3.3.37
Hardened Containment Venting System	Yes - FP	Section 2.3.3.38
Steam and Power Conversion Systems		
Main Steam System	Yes - SR, NSR, ATWS, EQ, FP, SBO	Section 2.3.4.1
Condensate/Demineralized Water System	Yes - SR, NSR, FP, SBO	Section 2.3.4.2

Table 2.2-1, Plant Level Scoping Results (Continued)

System, Structure, or Commodity Group	In Scope for SLR [a]	Reference
Reactor Feedwater System	Yes - SR, NSR, ATWS, EQ, FP, SBO	Section 2.3.4.3
Extraction Steam System	No	None
Heater Drains and Vents	Yes - NSR	Section 2.3.4.4
Miscellaneous Turbine Connections	Yes - NSR	Section 2.3.4.5
Condenser Circulating Water System	Yes - SR, NSR, EQ, FP	Section 2.3.4.6
Main Generator Hydrogen Cooling System	No	None
Gland Seal Water System	Yes - NSR	Section 2.3.4.7
Containments, Structures, and Component Supports		
Unit 1, Unit 2, and Unit 3 Reactor Buildings (includes Control Bay)	Yes - SR, ATWS, EQ, FP, SBO	Section 2.4.1
Unit 1, Unit 2, and Unit 3 Primary Containment Structures	Yes - SR, ATWS, EQ, FP, SBO	Section 2.4.2
Unit 1/2 Diesel Generator Building and Unit 3 Diesel Generator Building	Yes - SR, FP, SBO	Section 2.4.3
Intake Pumping Station	Yes - SR, FP, SBO	Section 2.4.4
Reinforced Concrete Chimney	Yes - SR, FP	Section 2.4.5
Standby Gas Treatment Building	Yes - SR, EQ, FP	Section 2.4.6
Off-Gas Treatment Building	Yes - SR, FP	Section 2.4.7
Equipment Access Lock	Yes - SR, FP	Section 2.4.8
Vacuum Pipe Building	Yes - SR, FP	Section 2.4.9
Vacuum Pump Building	No	None
Unit 1, Unit 2, and Unit 3 Turbine Buildings	Yes - NSR, ATWS, EQ, FP, SBO	Section 2.4.10
Radwaste Building	Yes - NSR, FP	Section 2.4.11
Plant Maintenance Building and Office Building	No	None
Service Building	Yes - FP	Section 2.4.12
Vent Vaults	Yes - NSR	Section 2.4.13
Guardhouse	No	None
Radwaste Evaporator Building	No	None

Table 2.2-1, Plant Level Scoping Results (Continued)

System, Structure, or Commodity Group	In Scope for SLR [a]	Reference
Security Diesel Building	No	None
Cooling Tower Pumping Stations Numbers. 1-7	No	None
Cooling Towers	No	None
Cooling Tower Bypass Outlets	No	None
Cooling Tower 480 V Substations	No	None
Gate Structure Number 1	No	None
Gate Structure Number 1A	No	None
Gate Structure Number 1B	No	None
Gate Structure Number 2	Yes - SR, FP	Section 2.4.14
Gate Structure Number 3	Yes - SR, FP, SBO	Section 2.4.15
Discharge Structure	No	None
Discharge Control Structure	Yes - NSR	Section 2.4.16
Circulating Water Conduits	Yes - FP	Section 2.4.17
Diesel High Pressure Fire Pump House	Yes - NSR, FP	Section 2.4.18
Sewage Treatment Facility	No	None
Sewage Analysis House	No	None
Sewage Lift Station	No	None
Radiation Monitoring Building	No	None
Communication Building	No	None
Bio-Thermal Research Facility	No	None
Low-Temp Pumping Station for Bio-Thermal Research	No	None
Hot Pump Wells Bio-Thermal Research Facility	No	None
Dewatering Facility	No	None
East Access Control Portal	No	None
West Access Control Portal	No	None
Sample and Water Quality Building	No	None
Raw Water Treatment Facility	No	None
Auxiliary RCW Supply Pump Station	No	None
Auxiliary Decay Heat Removal Cooling Towers	No	None

Table 2.2-1, Plant Level Scoping Results (Continued)

System, Structure, or Commodity Group	In Scope for SLR [a]	Reference
Alternate Decay Heat Removal Motor Control Center Building	No	None
Ecolochem Building	No	None
Hypochlorite Building	No	None
Central Alarm Station Building	No	None
Secondary Alarm System Building	No	None
Training and Visitor Center	No	None
Temporary Radwaste Storage Building	No	None
Radwaste Storage Building	No	None
Low Level Radwaste Storage Facility	Yes - SR, FP	Section 2.4.19
Fire Equipment House and Valve Pit	No	None
Uninterruptible Power Supply Building	No	None
Field Service Building	No	None
Paint and Sandblast Shop	No	None
Outage Fabrication Shop	No	None
Isolation Valve Pits	Yes - FP	Section 2.4.37
Plant Maintenance Building (123 Maintenance/Fire Operations Building)	No	None
Water and Oil Storage Building	No	None
Common Maintenance Building	No	None
Fish Collection Facility	No	None
Telephone Equipment House	No	None
Material and Procurement Complex	No	None
Trash Pipe Bridge	No	None
Meteorological Tower	No	None
Meteorological Monitoring Building	No	None
Facilities Maintenance Warehouse (Greenhouse)	No	None
Greenhouse Warehouse	No	None
Flammable Liquids Building	No	None

Table 2.2-1, Plant Level Scoping Results (Continued)

System, Structure, or Commodity Group	In Scope for SLR [a]	Reference
Facilities Maintenance Chemical Storage Building (Warm Water Control Station)	No	None
Overwinter Facility	No	None
Transformer Yard	Yes - FP, SBO	Section 2.4.20
161 kV Switchyard	Yes - SBO	Section 2.4.21
500 kV Switchyard	Yes - FP, SBO	Section 2.4.22
161 kV Capacitor Yard	No	None
4 kV Capacitor Yard	No	None
Shunt Reactor Yard	No	None
Condensate Water Storage Tanks Foundations, Trenches, and Tunnels	Yes - FP, SBO	Section 2.4.23
Nitrogen Storage Tank Foundation	Yes - FP	Section 2.4.24
Lube Oil Storage Tanks Foundations	No	None
Demineralizer Water Storage Tank Foundation	No	None
Transformer Oil Storage Tank Foundations	No	None
Fuel Oil Storage Tanks Foundations	No	None
Supplemental Diesel Generator Building	Yes - FP	Section 2.4.25
CAD System Storage Tank Foundations	Yes - SR, FP, SBO	Section 2.4.26
Acid Storage Area andChemical Injection System Tank	No	None
Cool Water Channel	No	None
Intake Channel	Yes - SR, FP, SBO	Section 2.4.27
North Bank of Cool Water Channel East of Gate Structure Number 2	Yes - SR, FP, SBO	Section 2.4.28
South Dike of Cool Water Channel between Gate Structures Number 2 and Number 3	Yes - SR, FP, SBO	Section 2.4.29
Warm Water Channel	No	None

Table 2.2-1, Plant Level Scoping Results (Continued)

System, Structure, or Commodity Group	In Scope for SLR [a]	Reference
Switchyard Drain Channel	No	None
Sewage Treatment Lagoon	No	None
Earth Berm	Yes - SR	Section 2.4.30
RHRSW Tunnel	Yes - SR, FP	Section 2.4.31
Electrical Cable Tunnel (from Intake Pumping Structure to Powerhouse)	Yes - SR, FP, SBO	Section 2.4.32
Underground Concrete Encased Structures	Yes - SR, FP, SBO	Section 2.4.33
Plant Administration Building	No	None
North and South Administration Building	No	None
East Access Facility	No	None
South Access Facility	No	None
Diesel Fire Pump Building	No	None
Yard, General	Yes - SR, FP	Section 2.4.34
South Access Retaining Wall	Yes - SR	Section 2.4.35
Cooling Tower Lift Pump Bearing Lube Water Pump Station	No	None
Independent Spent Fuel Storage Installation (ISFSI) Pads	No	None
Upper Deployment Pad	No	None
Lower Deployment Pad	No	None
ISFSI Equipment Storage Building	No	None
FLEX Storage Building	No	None
Microwave Tower	No	None
Penetrations and Sleeves	Yes - SR, NSR, ATWS, EQ, FP, SBO	Section 2.4.36
Electrical Conduits	Yes - SR, NSR, ATWS, EQ, FP, SBO	Section 2.4.36
Cable Trays and Cable Support	Yes - SR, NSR, ATWS, EQ, FP, SBO	Section 2.4.36

Table 2.2-1, Plant Level Scoping Results (Continued)

System, Structure, or Commodity Group	In Scope for SLR [a]	Reference
Building Doors and Hatches	Building doors and hatches of in-scope structures evaluated as structural components during screening and aging management review.	Section 2.4
Electrical and Instrumentation and Controls Systems		
Spare Local Panels and Miscellaneous	Yes - Bounding approach	Section 2.5.1
Control Bay Panels	Yes - Bounding approach	Section 2.5.1
Feedwater Level Control System	Yes - Bounding approach	Section 2.5.1
Turbine Generator Control System	Yes - Bounding approach	Section 2.5.1
Seismic Monitoring System	Yes - Bounding approach	Section 2.5.1
Annunciators	Yes - Bounding approach	Section 2.5.1
Temperature Monitoring System	Yes - Bounding approach	Section 2.5.1
Electrical Distribution System	Yes - Bounding approach and SBO recovery	Section 2.5.1
Plant Computer System	Yes - Bounding approach	Section 2.5.1
Radiation Monitoring System (electrical and I&C components)	Yes - Bounding approach	Section 2.5.1
Neutron Monitoring System	Yes - Bounding approach	Section 2.5.1
Traversing Incore Probe System	Yes - Bounding approach	Section 2.5.1
Recirculation Flow Control System	Yes - Bounding approach	Section 2.5.1
Reactor Protection System	Yes - Bounding approach	Section 2.5.1
4 kV Unit Boards	Yes - Bounding approach and SBO recovery	Section 2.5.1
4 kV Common Boards	Yes - Bounding approach	Section 2.5.1
4 kV Unit Start Board 1 and Start Bus 1	Yes - Bounding approach and SBO recovery	Section 2.5.1
4 kV Cooling Tower Switchgear	Yes - Bounding approach	Section 2.5.1
4 kV Biothermal Research Boards	Yes - Bounding approach	Section 2.5.1
4 kV Bus Tie Board	Yes - Bounding approach and SBO recovery	Section 2.5.1
4 kV Shutdown Boards and Buses	Yes - Bounding approach and SBO recovery	Section 2.5.1
480 VAC Common Boards	Yes - Bounding approach	Section 2.5.1

Table 2.2-1, Plant Level Scoping Results (Continued)

System, Structure, or Commodity Group	In Scope for SLR [a]	Reference
480 VAC Diesel Auxiliary Boards	Yes - Bounding approach	Section 2.5.1
480 VAC Unit Boards	Yes - Bounding approach	Section 2.5.1
480 VAC Shutdown Boards	Yes - Bounding approach	Section 2.5.1
480 VAC Cooling Tower Boards	Yes - Bounding approach	Section 2.5.1
480 VAC Biothermal Boards	Yes - Bounding approach	Section 2.5.1
Main Bank Transformers	Yes - Bounding approach and SBO recovery	Section 2.5.1
480 VAC Service Building Main Board	Yes - Bounding approach	Section 2.5.1
480 VAC Transformer Yard Distribution Cabinet	Yes - Bounding approach	Section 2.5.1
480 VAC Lighting Boards	Yes - Bounding approach	Section 2.5.1
480 VAC Water Supply Board	Yes - Bounding approach	Section 2.5.1
161 kV Switchyard	Yes - Bounding approach and SBO recovery	Section 2.5.1
500 kV Switchyard/Main Generators 2 and 3	Yes - Bounding approach and SBO recovery	Section 2.5.1
Unit Station Service Transformers	Yes - Bounding approach and SBO recovery	Section 2.5.1
Communications System	Yes - Bounding approach	Section 2.5.1
Common Station Service Transformers	Yes - Bounding approach and SBO recovery	Section 2.5.1
Cooling Tower Transformers	Yes - Bounding approach	Section 2.5.1
240 VAC Lighting System (Emergency Lighting)	Yes - Bounding approach and SBO recovery	Section 2.5.1
250 VDC Power System	Yes - Bounding approach and SBO recovery	Section 2.5.1
Plant Preferred 120 VAC Distribution System	Yes - Bounding approach	Section 2.5.1
Plant non-preferred 120 VAC Distribution System	Yes - Bounding approach	Section 2.5.1
48 VDC Distribution System	Yes - Bounding approach	Section 2.5.1
Unit Preferred 120 VAC Distribution System	Yes - Bounding approach	Section 2.5.1
120 VAC Instrumentation/ Control Bus	Yes - Bounding approach	Section 2.5.1
125 VDC Diesel Generator Batteries	Yes - Bounding approach	Section 2.5.1

Table 2.2-1, Plant Level Scoping Results (Continued)

System, Structure, or Commodity Group	In Scope for SLR [a]	Reference
Data Logger	Yes - Bounding approach	Section 2.5.1
Emergency Core Cooling System (ECCS) Analog Trip Unit Inverters	Yes - Bounding approach	Section 2.5.1
Operations Recorder	Yes - Bounding approach	Section 2.5.1
480 VAC Load Shedding Logic	Yes - Bounding approach	Section 2.5.1
Plant Computer System	Yes - Bounding approach	Section 2.5.1
Generator Bus	Yes - Bounding approach	Section 2.5.1
480 VAC Reactor Ventilation Boards	Yes - Bounding approach	Section 2.5.1
480 VAC Control Bay Ventilation Boards	Yes - Bounding approach	Section 2.5.1
480 VAC Turbine Building Ventilation Boards	Yes - Bounding approach	Section 2.5.1
480 VAC Reactor Motor Operated Valve Boards	Yes - Bounding approach	Section 2.5.1
480 VAC Turbine Motor Operated Valve Boards	Yes - Bounding approach	Section 2.5.1
480 VAC Condensate Demineralizer Boards	Yes - Bounding approach	Section 2.5.1
480 VAC Auxiliary Boiler Boards	Yes - Bounding approach	Section 2.5.1
480 VAC Water/Oil Storage Board	Yes - Bounding approach	Section 2.5.1
480 VAC Radwaste Boards	Yes - Bounding approach	Section 2.5.1
480 VAC Service Building Ventilation Board	Yes - Bounding approach	Section 2.5.1
480 VAC Office Building Ventilation Board	Yes - Bounding approach	Section 2.5.1
480 VAC Power Cabinets	Yes - Bounding approach	Section 2.5.1
480 VAC Gatehouse Panel Board	Yes - Bounding approach	Section 2.5.1
240 VAC Distribution Cabinet	Yes - Bounding approach	Section 2.5.1
Battery Boards 1,2,3,4,5 and 6	Yes - Bounding approach and SBO recovery	Section 2.5.1
250 VDC Reactor Motor Operated Valve Boards	Yes - Bounding approach and SBO recovery	Section 2.5.1
250 VDC Distribution Boards	Yes - Bounding approach and SBO recovery	Section 2.5.1
24 VDC Distribution System	Yes - Bounding approach	Section 2.5.1

Table 2.2-1, Plant Level Scoping Results (Continued)

System, Structure, or Commodity Group	In Scope for SLR [a]	Reference
480 V Power Outlets	Yes - Bounding approach	Section 2.5.1
208/120 VAC Plant Computer Power System	Yes - Bounding approach	Section 2.5.1
Fuse Failure Alarm	Yes - Bounding approach	Section 2.5.1
125 VDC Distribution System	Yes - Bounding approach	Section 2.5.1
120 VAC Electrical Distribution System	Yes - Bounding approach	Section 2.5.1
250 VDC Distribution System	Yes - Bounding approach	Section 2.5.1
480 VAC Distribution System	Yes - Bounding approach and SBO recovery	Section 2.5.1
4 kV Distribution System	Yes - Bounding approach and SBO recovery	Section 2.5.1
500 kV/161 kV Off Site Power System	Yes - Bounding approach and SBO recovery	Section 2.5.1
25 Series Panels (Local Panels)	Yes - Bounding approach	Section 2.5.1

a. SR - Safety-Related (10 CFR 54.4(a)(1)),
NSR - Non Safety-Related (10 CFR 54.4(a)(2)),
ATWS - Anticipated Transient Without Scram (10 CFR 54.4(a)(3) for ATWS),
EQ - Equipment Qualification (10 CFR 54.4(a)(3) for EQ),
FP - Fire Protection (10 CFR 54.4(a)(3) for FP),
SBO - Station Blackout (10 CFR 54.4(a)(3) for SBO), and
Bounding approach - described in Section 2.1.6.1

2.3 SCOPING AND SCREENING RESULTS: MECHANICAL

The scoping and screening results for mechanical systems consist of lists of components and component groups that require aging management reviews, that are grouped, and presented on a system basis. Brief descriptions of mechanical systems within the scope of subsequent license renewal are provided as background information. Mechanical system intended functions are provided for in-scope systems.

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

- Reactor Vessel, Internals, and Reactor Coolant System (2.3.1)
- Engineered Safety Features and Reactor Core Isolation Cooling Systems (2.3.2)
- Auxiliary Systems (2.3.3)
- Steam and Power Conversion Systems (2.3.4)

2.3.1 Reactor Vessel, Internals and Reactor Coolant System

The following systems are addressed in this section:

- Reactor Vessel (2.3.1.1)
- Reactor Vessel Internals (2.3.1.2)
- Reactor Vessel Vents and Drains System (2.3.1.3)
- Reactor Recirculation System (2.3.1.4)
- Fuel Assemblies (2.3.1.5)

2.3.1.1 Reactor Vessel

Description

The Reactor Vessel provides a floodable volume and coolant distribution to mitigate accidents.

The Reactor Vessel is part of the reactor coolant pressure boundary (RCPB) which provides physical support for the reactor core and reactor vessel internals.

The Reactor Vessel system includes the reactor vessel, including nozzles, penetrations, and safe ends and welds to connecting piping. The reactor vessel is a vertical, cylindrical pressure vessel with hemispherical heads and is of welded construction. The cylindrical shell and bottom hemispherical head of the reactor vessel are fabricated of low alloy steel plate. The shell is clad on the interior with a stainless steel overlay, and the bottom head with an Inconel overlay.

To withstand external and internal loadings while maintaining a high degree of corrosion resistance, a high-strength, carbon-alloy steel is used as the base metal with an internal cladding applied by weld overlay to the cylindrical shell and bottom head. Use of the ASME Boiler and Pressure Vessel Code, Section III, Class A, pressure vessel code design criteria provides assurance that a vessel designed, built, and operated within its design limits has an extremely low probability of failure due to any known failure mechanism.

The following systems are credited for maintaining the reactor coolant pressure boundary:

- Main Steam
- Feedwater

- Boiler Drains and Vents
- Sampling and Water Quality
- Standby Liquid Control (SLC)
- Reactor Recirculation
- Reactor Water Cleanup
- Reactor Core Isolation Cooling
- High Pressure Coolant Injection
- Residual Heat Removal
- Core Spray
- Control Rod Drive (CRD)
- Neutron Monitoring
- Traversing Incore Probe

The reactor vessel is discussed in FSAR Sections 4.2, 7.8 and Appendices J, K, and L. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide reactor coolant pressure boundary. The reactor vessel forms a barrier against the release of reactor coolant and radioactive material. 10 CFR 54.4(a)(1)
2. Provides support to the reactor internals. The reactor vessel, along with the reactor internals, maintains a floodable volume within the reactor. 10 CFR 54.4(a)(1)
3. Provides structural support or restraint to SSCs in the scope of SLR. The reactor vessel support skirt and stabilizer brackets provide structural support for the reactor vessel. 10 CFR 54.4(a)(1)
4. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The reactor vessel must remain intact to allow maintenance of the reactor vessel coolant level. 10 CFR 54.4(a)(3)
5. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). The reactor vessel provides a portion of the reactor coolant pressure boundary. 10 CFR 54.4(a)(3)
6. Relied upon 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). 10 CFR 54.4(a)(3)
    - Provide reactor coolant pressure boundary. The reactor vessel forms a barrier against the release of reactor coolant and radioactive material.
    - The reactor vessel, along with reactor vessel internals, maintains a floodable volume. Floodable volume is required to achieve Nuclear Safety Performance Criteria (NSPC) Inventory Control Performance Criteria.

FSAR References

Section 4.2

Section 7.8
Appendices J, K, and L

Subsequent License Renewal Boundary Drawings
1-47E801-1-SLR
1-47E803-1-SLR
1-47E803-5-SLR
1-47E811-1-SLR
1-47E814-1-SLR
1-47E817-1-SLR
1-47E854-1-SLR
2-47E801-1-SLR
2-47E803-5-SLR
2-47E811-1-SLR
2-47E814-1-SLR
2-47E817-1-SLR
2-47E854-1-SLR
3-47E801-1-SLR
3-47E803-1-SLR
3-47E803-5-SLR
3-47E811-1-SLR
3-47E814-1-SLR
3-47E817-1-SLR
3-47E854-1-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.1-1, Reactor Vessel.

Table 2.3.1-1, Reactor Vessel

Component Type	Passive Intended Functions
(N-1A/B Recirculation Outlet) Reactor Vessel Nozzle	Pressure Boundary
(N-1A/B Recirculation Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N-2A-K Recirculation Inlet) Reactor Vessel Nozzle	Pressure Boundary
(N-2A-K Recirculation Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N-2A-K Recirculation Inlet) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow
(N-3A-D Steam Outlet) Reactor Vessel Nozzle	Pressure Boundary

Table 2.3.1-1, Reactor Vessel (Continued)

Component Type	Passive Intended Functions
(N-3A-D Steam Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N-4A-F Feedwater) Reactor Vessel Nozzle	Pressure Boundary
(N-4A-F Feedwater) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N-4A-F Feedwater) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow
(N-5A/B Core Spray) Reactor Vessel Nozzle	Pressure Boundary
(N-5A/B Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N-5A/B Core Spray) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow
(N-6A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary
(N-6A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N-7 Head Vent) Reactor Vessel Nozzle	Pressure Boundary
(N-7 Head Vent) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N-8A/B Jet Pump Instrumentation) Reactor Vessel Nozzle	Pressure Boundary
(N-8A/B Jet Pump Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N-9 CRD Return) Reactor Vessel Nozzle	Pressure Boundary
(N-9 CRD Return) Reactor Vessel Nozzle, Safe Ends, and Welds (including cap)	Pressure Boundary
(N10 Core Plate Differential Pressure (D/P) and SLC) Reactor Vessel Nozzle	Pressure Boundary
(N10 Core Plate D/P and SLC) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N11A/B, N12A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary
(N11A/B, N12A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N13 Flange Leak-Off) Reactor Vessel Nozzle	Pressure Boundary, Direct Flow
(N14 Flange Leak-Off) Reactor Vessel Nozzle	Pressure Boundary
(N15 Bottom Drain) Reactor Vessel Nozzle	Pressure Boundary
(N15 Bottom Drain) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
(N16A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary

Table 2.3.1-1, Reactor Vessel (Continued)

Component Type	Passive Intended Functions
(N16A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary
Bolting (Class 1)	Mechanical Closure
Bolting (Closure)	Mechanical Closure
Flow Device	Pressure Boundary, Throttle
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" nominal pipe size (NPS) and greater than or equal to 1" NPS	Pressure Boundary
Reactor Vessel (Bottom Head and Welds)	Pressure Boundary
Reactor Vessel (Shell and Welds)	Pressure Boundary
Reactor Vessel (Upper Head)	Pressure Boundary
Reactor Vessel Closure Flange Assembly Components	Pressure Boundary, Mechanical Closure
Reactor Vessel External Attachments, Support Skirt, Stabilizer Bracket, and Welds	Structural Support
Reactor Vessel Flange Leak Detection Line	Pressure Boundary
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Pressure Boundary, Direct Flow, Structural Support to maintain core configuration and flow distribution
Piping, Piping Components (Valve Body)	Pressure Boundary
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary

The aging management review results for these components are provided in Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation.

2.3.1.2 Reactor Vessel Internals

Description

The reactor vessel internals are installed to properly distribute the flow of coolant delivered to the vessel, to locate and support the fuel assemblies, and to provide an inner volume containing the core that can be flooded following a break in the nuclear system process barrier external to the reactor vessel. The reactor vessel internals are the following components:

The reactor vessel internals include partitions between regions within the reactor vessel to provide proper coolant distribution, thereby allowing power operation without fuel damage due to inadequate cooling. It provides positioning and support for the fuel assemblies, control rods, incore flux monitors, and other components to assure that control rod movement is not impaired. he Reactor Vessel is a floodable volume in which the core can be adequately cooled if there is a breach in the nuclear system process barrier external to the reactor vessel. The reactor vessel internals are considered safety-related because most of its components are safety-related and work together to ensure safe reactor operation. The reactor vessel internals also includes nonsafety-related components such as the reactor steam dryer assembly that have the potential for spatial and structural interactions with safety-related SSCs.

The reactor vessel internals are the following components:

- Core shroud
- Shroud head and steam separator assembly
- Core support (core plate)
- Top guide
- Fuel support pieces
- Control rod guide tubes
- Jet pump assemblies
- Steam dryers
- Feedwater spargers
- Core spray lines and spargers
- Vessel head cooling spray nozzle
- Differential pressure and liquid control line
- In-core instrumentation (Source Range Monitor, Intermediate Range Monitor, Local Power Range Monitor) dry tubes
- Incore neutron flux monitor (Traversing Incore Probe) guide tubes
- Startup neutron sources
- Surveillance sample holders

The differential pressure and [standby] liquid control line serves a dual function within the reactor vessel to inject standby liquid control solution into the coolant stream (discussed in FSAR Section 3.8, Standby Liquid Control System) and to sense the differential pressure across the core support assembly (see FSAR Section 4.2, Reactor Vessel and Appurtenances Mechanical Design).

The reactor vessel internals are discussed in FSAR Sections 3.3, 4.2 and Appendices J, K, and L. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

<u>Intended Functions</u>

1. Maintain reactor core assembly geometry. The reactor vessel provides support to the reactor internals. The reactor vessel, along with the reactor vessel internals, maintains a floodable volume within the reactor. 10 CFR 54.4(a)(1)
2. Introduce negative reactivity to achieve and maintain subcritical reactor condition. The control rods and CRD assemblies adjust the concentration of the neutron absorber in the core during normal operations and shutdown conditions. 10 CFR 54.4(a)(1)
3. Introduce emergency negative reactivity to make the reactor subcritical. When a Reactor Protection System scram signal is received, high pressure water is applied to the CRD assemblies to rapidly insert each control rod into the core. he core plate differential pressure and standby liquid control line provides a flow path for injecting a neutron absorber into the reactor core when control rods are unavailable. 10 CFR 54.4(a)(1)

4. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. Neutron flux detectors within the reactor core initiate a Reactor Protection System scram signal to shutdown the reactor upon a high flux condition. 10 CFR 54.4(a)(1)
5. Provide emergency core cooling where the equipment provides coolant directly to the core. The core spray piping and spargers, internal to the reactor vessel, distribute emergency core cooling flow within the shroud to the reactor core. 10 CFR 54.4(a)(1)
6. Resist spatial interaction of nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The reactor vessel internals include nonsafety-related components such as the steam dryer assembly which have the potential for spatial interaction with safety-related SSCs in the reactor vessel. 10 CFR 54.4(a)(2)
7. Resist structural interactions from mechanically connected nonsafety-related components that could prevent satisfactory accomplishment of a safety-related function. The reactor vessel internals include nonsafety-related components such as the steam dryer assembly that help maintain structural integrity of the safety-related portions of the system. 10 CFR 54.4(a)(2)
8. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). The reactor vessel internals provide the flow path for standby liquid control injection. 10 CFR 54.4(a)(3)
9. Relied upon 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). The reactor vessel internals maintain reactor core assembly geometry and control rod insertion capability to introduce negative reactivity to make the reactor subcritical. 10 CFR 54.4(a)(3)
   - This system is necessary to assure control rod movement is not impaired to meet NSPC Reactivity Control. Introduce negative reactivity to make the reactor subcritical.
   - Maintain reactor core assembly geometry. The reactor vessel provides support to the reactor vessel internals. The reactor vessel, along with the reactor vessel internals, maintains a floodable volume within the reactor.

FSAR References

Section 3.3

Section 4.2

Appendices J, K, L

Subsequent License Renewal Boundary Drawings

1-47E814-1-SLR

1-47E817-1-SLR

2-47E814-1-SLR

2-47E817-1-SLR

3-47E814-1-SLR

3-47E817-1-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.1-2, Reactor Vessel Internals.

Table 2.3.1-2, Reactor Vessel Internals

Component Type	Passive Intended Functions
Core Shroud and Core Plate Access hole cover (Mechanical - Units 1 and 2)	Mechanical Closure, Direct Flow
Core Shroud and Core Plate: Access hole cover (Welded - Units 2 and 3)	Direct Flow
Core Shroud and Core Plate: Core Shroud (upper, central, lower)	Structural Support to maintain core configuration and flow distribution
Core Shroud and Core Plate: Core Shroud support structure (shroud support cylinder, shroud support plate, shroud support legs)	Structural Support to maintain core configuration and flow distribution
Core Shroud and Core Plate: Core plate, Core plate bolts	Structural Support to maintain core configuration and flow distribution
Core Spray Lines and Spargers: Core spray lines (headers), Spray rings, Spray nozzles, Thermal sleeves	Direct Flow, Spray
Core Spray Sparger Nozzle Elbows	Direct Flow
CRD Housing	Pressure Boundary, Structural Support
In-core Instrumentation: Intermediate Range Monitor Dry Tubes, Local Power Range Monitor Dry Tubes, Source Range Monitor Dry Tubes, and In-core Neutron Flux Monitor (Traversing Incore Probe) Guide Tubes	Structural Support, Pressure Boundary
Jet Pump Assemblies: Hold-down beam bolts	Mechanical Closure
Jet Pump Assemblies: Jet pump sensing line	Direct Flow
Jet Pump Assemblies: Thermal sleeve inlet header, Riser brace arm, Hold-down beams, and Wedges	Structural Support
Reactor Vessel Internal Components	Structural Support to maintain core configuration and flow distribution
Reactor Vessel Internals Components (Core Spray Repair Hardware)	Pressure Boundary, Structural Support
Reactor Vessel Internals Components (Jet Pump Auxiliary Spring Wedges)	Structural Support
Reactor Vessel Internals Components (Jet Pump Riser Clamp)	Structural Support
Reactor Vessel Internals Components (Jet Pump Slip Joint Clamps)	Structural Support
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Structural Support to maintain core configuration and flow distribution, Throttle

Table 2.3.1-2, Reactor Vessel Internals (Continued)

Component Type	Passive Intended Functions
Reactor Vessel Internals Components: Steam Dryers	Structural Support
Reactor Vessel Internals Components: Top Guide	Structural Support to maintain core configuration and flow distribution

The aging management review results for these components are provided in Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation.

2.3.1.3 Reactor Vessel Vents and Drains System

Description

The Reactor Vessel (RV) Vents and Drains System consists of manual valves and piping connected to the Reactor Coolant Pressure Boundary inside primary containment and includes the RV head vent piping, the RV bottom head drain piping, and the blowdown piping for the Nuclear System Pressure Relief System, from the Main Steam Relief Valves (MSRV) to the pressure suppression chamber. All system piping and components are located within the primary containment. The RV Vents and Drains System for each unit share no components with the other units.

Some of the RV Vents and Drains System non-safety functions are to provide for venting the RV head to the drywell equipment drain sump during filling and draining operations.

The RV Vents and Drains System components that are non-safety related include non-safety-related fluid filled lines in the Reactor Building that have the potential for spatial interactions with safety-related SSCs. The RV Vents and Drains non-safety-related piping is mechanically connected and provide structural support to the safety-related portion of the RV Vents and Drains System.

The RV Vents and Drains System components that are non-safety-related meet the criteria of 10 CFR 54.4(a)(2) as they include non-safety-related fluid filled lines in the Reactor Building that have the potential for spatial interactions with safety-related SSCs. The RV Vents and Drains non-safety-related piping is mechanically connected and provide structural support to the safety-related portion of the RV Vents and Drains System, and therefore meets the criterion of 10 CFR 54.4(a)(2).

The RV Vents and Drains system is discussed in FSAR Sections 4.2 and 4.4. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide reactor coolant pressure boundary. The RV Vents and Drains System is a part of the reactor coolant pressure boundary (RCPB), which forms a barrier against the release of reactor coolant and radioactive material. 10 CFR 54.4(a)(1)
2. Provide the flow path for the MSRV steam blowdown to the primary containment suppression pool. Steam released by the MSRVs shall be vented to the pressure suppression chamber to

prevent increasing the drywell atmosphere radiation, pressure, temperature, and humidity. 10 CFR 54.4(a)(1)

3. Resist spatial interactions from non-safety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The RV Vents and Drains System includes non-safety-related fluid filled lines in the Reactor Building which have the potential for spatial interaction with safety-related SSCs in the Reactor Building. 10 CFR 54.4(a)(2)
4. Resist structural interactions from mechanically connected non-safety-related piping that could prevent satisfactory accomplishment of a safety-related function. The RV Vents and Drains System non-safety-related piping is mechanically connected and provide structural support to the safety-related portion of the RV Vents and Drains System. 10 CFR 54.4(a)(2)
5. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). The RV Vents and Drains System provides a portion of the reactor coolant pressure boundary. 10 CFR 54.4(a)(3)
6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)
   - The RV Vents and Drains System provides a portion of the reactor coolant pressure boundary.
   - The RV Vents and Drains System provides a path for the MSRVs steam blowdown to the primary containment suppression pool. Steam released by the MSRVs shall be vented to the pressure suppression chamber to prevent increasing the drywell atmosphere radiation, pressure, temperature, and humidity.

<u>FSAR References</u>

Section 4.2

Section 4.4

<u>Subsequent License Renewal Boundary Drawings</u>

1-47E817-1-SLR

2-47E810-1-SLR

2-47E817-1-SLR

3-47E817-1-SLR

1-47E801-1-SLR

1-47E803-1-SLR

2-47E801-1-SLR

2-47E803-5-SLR

3-47E801-1-SLR

3-47E803-1-SLR

1-47E810-1-SLR

3-47E810-1-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.1-3, Reactor Vessel Vents and Drains System.

Table 2.3.1-3, Reactor Vessel Vents and Drains System

Component Type	Passive Intended Functions
Bolting (Closure)	Mechanical Closure
Piping, Piping Components	Pressure Boundary
Piping, Piping Components (Class 1)	Pressure Boundary
Piping, Piping Components (Valve Body)	Pressure Boundary
Piping, Piping Components (Valves Body (Class 1))	Pressure Boundary

The aging management review results for these components are provided in Table 3.1.2-3, Reactor Vessel Vents and Drains System - Summary of Aging Management Evaluation.

2.3.1.4 Reactor Recirculation System

Description

The Reactor Recirculation System is a reactivity control system that serves to control reactor power levels by varying the coolant rate through the core over a limited range so that greater versatility is available in making power adjustments without the use of control rods.

The Reactor Recirculation System consists of two independent loops, external to the reactor vessel, each with a motor driven centrifugal pump, suction and discharge valves, and piping. The Reactor Recirculation System is part of the reactor coolant pressure boundary, and functions to maintain the pressure boundary during normal operation, transients, and accident scenarios to prevent the release of radioactive liquid and gas. The system piping and pump design pressures are based on peak steam pressure in the reactor dome plus the static head above the lowest point in the recirculation loop.

The Reactor Recirculation System provides flow paths out of the reactor vessel for Residual Heat Removal (RHR) System and Reactor Water Cleanup (RWCU) System and into the reactor vessel for RHR shutdown cooling and low pressure coolant injection.

The coolant flow rate through the reactor core is varied by using adjustable speed drives and flow control instrumentation to change the speed of the centrifugal pumps to control the recirculation system drive flow rate.

The Reactor Recirculation System includes non-safety-related fluid filled components (drain lines, seal supply lines, instrument piping, etc.) in the Drywell and Reactor Building which have the potential for spatial interaction with safety-related components. Also, non-safety-related Reactor Recirculation components are mechanically connected to safety-related Reactor Recirculation piping.

A recirculation pump trip on reactor high pressure or reactor low water level has been provided to limit the consequences of a failure to scram during a transient.

The Reactor Recirculation System is discussed in FSAR Sections 4.3 and 7.9. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide reactor coolant pressure boundary. The Reactor Recirculation System forms a barrier to minimize the release of reactor coolant and radioactive material to the Reactor Building. 10 CFR 54.4(a)(1)
2. Provide primary containment boundary. The Reactor Recirculation System includes primary containment isolation valves. 10 CFR 54.4(a)(1)
3. Sense process conditions and generate signals for reactor trip or engineered safety features actuations. The Reactor Recirculation System includes instrumentation and process controls that provide input signals to the Reactor Protection System and Emergency Core Cooling Systems. 10 CFR 54.4(a)(1)
4. Resist spatial interactions from non-safety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Reactor Recirculation System includes non-safety-related fluid filled components which have the potential for spatial interaction with safety-related components. 10 CFR 54.4(a)(2)
5. Resist structural interactions from mechanically connected non-safety-related piping that could prevent satisfactory accomplishment of a safety-related function. The Reactor Recirculation System includes non-safety-related piping that is relied upon to preserve the structural integrity of safety-related Reactor Recirculation piping. 10 CFR 54.4(a)(2)
6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). The Reactor Recirculation System provides a portion of the reactor coolant pressure boundary. 10 CFR 54.4(a)(3)
7. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). Reactor Recirculation System components receive the recirculation pump trip signal from the Reactor Protection System. 10 CFR 54.4(a)(3)
8. Portions of this system are relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). This system includes environmentally qualified electrical components. 10 CFR 54.4(a)(3)
9. Relied upon 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). 10 CFR 54.4(a)(3).
   - The Reactor Recirculation pump must be turned off during low pressure coolant injection to meet NSPC Inventory Control Performance Criteria.
   - Reactor Recirculation pump suction or discharge valve must be closed during shutdown cooling to meet NSPC Decay Heat Removal Performance Criteria.
   - The Reactor Recirculation System maintains the reactor coolant pressure boundary.

FSAR References

Section 3.7.6

Section 4.3

Section 5.2.3

Section 7.8

Section 7.9

Section 7.19

Subsequent License Renewal Boundary Drawings

1-47E817-1-SLR

1-47E817-3-1-SLR

1-47E817-3-3-SLR

1-47E820-2-SLR

1-47E822-1-SLR

1-47E844-2-SLR

2-47E817-1-SLR

2-47E817-3-1-SLR

2-47E817-3-3-SLR

2-47E820-2-SLR

2-47E822-1-SLR

2-47E844-2-SLR

3-47E817-1-SLR

3-47E817-3-1-SLR

3-47E817-3-3-SLR

3-47E820-2-SLR

3-47E822-1-SLR

3-47E844-2-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.1-4, Reactor Recirculation System.

Table 2.3.1-4, Reactor Recirculation System

Component Type	Passive Intended Functions
Bolting (Class 1)	Mechanical Closure
Bolting (Closure)	Mechanical Closure
Flow Device	Pressure Boundary, Throttle
Flow Device (Class 1)	Pressure Boundary, Throttle
Heat Exchanger - (Recirculation Pump Seal Cooler) Shell Side Components	Pressure Boundary

Table 2.3.1-4, Reactor Recirculation System (Continued)

Component Type	Passive Intended Functions
Heat Exchanger - (Recirculation Pump Seal Cooler) Tubes	Pressure Boundary
Heat Exchanger - Variable Frequency Drives	Pressure Boundary
Piping, Piping Components (Hoses)	Pressure Boundary
Piping Elements	Pressure Boundary
Piping, Piping Components	Pressure Boundary,
Piping, Piping Components: Class 1 greater than or equal to 4" NPS	Pressure Boundary
Piping, Piping Components: Class 1 piping, fittings, and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary
Pump Casing (Recirculation Pump)	Pressure Boundary
Piping, Piping Components (Strainers)	Filter
Tanks (Recirc Pump Motor Upper and Lower Bearing Oil Reservoir)	Pressure Boundary
Piping, Piping Components (Valve Body)	Pressure Boundary,
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary

The aging management review results for these components are provided in Table 3.1.2-4, Reactor Recirculation System - Summary of Aging Management Evaluation.

2.3.1.5 Fuel Assemblies

Description

The Fuel Assemblies consist of nuclear fuel bundles that are high integrity assemblies of fissionable material that can be arranged in a critical array. Each nuclear fuel bundle must be capable of transferring the generated fission heat to the circulating coolant water while maintaining structural integrity and containing the fission products.

The nuclear fuel bundles are designed to assure that fuel damage limits will not be exceeded during either normal operation or anticipated operational occurrences. The Fuel Assemblies are utilized as the initial barrier for containment of fission products.

There are 764 nuclear fuel bundles in each reactor, with each nuclear fuel bundle consisting of a matrix of fuel rods.

Intended Functions

1. Maintain reactor core assembly geometry. The fuel assembly maintains geometry for any event to ensure core cooling, core reactivity control, and the integrity of the fuel cladding as a radioactive material boundary. 10 CFR 54.4(a)(1)

FSAR References

Section 3.2

Section 3.3

Section 3.6

Section 3.7

Section 10.2

Section 10.3

Appendix N

Subsequent License Renewal Boundary Drawings

Not applicable.

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.1-5, Fuel Assemblies.

Table 2.3.1-5, Fuel Assemblies

Component Type	Passive Intended Functions
Fuel Assemblies	Maintain reactor core assembly geometry. The fuel assembly maintains geometry for any event to ensure core cooling, core reactivity control, and the integrity of the fuel cladding as a radioactive material boundary.

The aging management review results for these components are provided in Table 3.1.2-5, Fuel Assemblies - Summary of Aging Management Evaluation.

2.3.2 Engineered Safety Features and Reactor Core Isolation Cooling Systems

The following systems are addressed in this section:

- Containment System (2.3.2.1)
- Standby Gas Treatment System (2.3.2.2)
- Reactor Core Isolation Cooling System (2.3.2.3)
- High Pressure Coolant Injection System (2.3.2.4)
- Residual Heat Removal System (2.3.2.5)
- Core Spray System (2.3.2.6)
- Containment Atmosphere Dilution System (2.3.2.7)

2.3.2.1 Containment System

Description

For the purpose of SLR, the Containment System includes the mechanical portions of the following systems, subsystems and components.

- Primary Containment System
- Primary Containment Isolation System
- Traversing In-Core Probe System
- Secondary Containment System
- Reactor/Refuel Zone Ventilation System

A description of each of these systems is provided below.

Primary Containment System

The Primary Containment System of each unit employs a pressure suppression containment system which houses the reactor vessel, the reactor coolant recirculating loops, and other branch connections of the Reactor Coolant System. The pressure suppression system consists of a drywell, a pressure suppression chamber (alternatively referred to as the torus or wetwell) which stores a large volume of water, a connecting vent system between the drywell and the pressure suppression chamber, isolation valves, containment cooling systems, equipment for establishing and maintaining a pressure differential between the drywell and pressure suppression chamber, and other service equipment.

In the event of a process system piping failure within the drywell, reactor water and steam would be released into the drywell air space. The resulting increased drywell pressure would then force a mixture of air, steam, and water through the vents into the pool of water which is stored in the pressure suppression chamber. The steam would condense rapidly and completely in the pressure suppression pool, resulting in rapid pressure reduction in the drywell. Air that is transferred to the pressure suppression chamber pressurizes the chamber and is subsequently vented to the drywell to equalize the pressure between the two volumes.

Cooling systems are provided to remove heat from the drywell and from the water in the pressure suppression chamber, thus cooling the primary containment, when required, under accident conditions.

The Primary Containment System is discussed in FSAR Sections 5.2.3, 5.2.5, 14.6, and 14.12.

The results of screening evaluations for the following components (valves, piping, penetrations, structural steel, etc.) that are essential for primary containment integrity are presented the associated system's screening evaluation in the following in the following sections of this application.

Section Number	System Name
2.3.4.1	Main Steam
2.3.4.2	Condensate/Demineralized Water
2.3.4.3	Reactor Feedwater
2.3.3.11	Control Air
2.3.3.12	Service Air
2.3.3.15	Sampling And Water Quality
2.3.3.18	Standby Liquid Control
2.3.2.2	Standby Gas Treatment
2.3.1.4	Reactor Recirculation
2.3.3.22	Reactor Water Cleanup
2.3.3.23	Reactor Building Closed Cooling Water
2.3.2.3	Reactor Core Isolation Cooling
2.3.2.4	High Pressure Coolant Injection
2.3.2.5	Residual Heat Removal
2.3.2.6	Core Spray
2.3.3.25	Containment Inerting
2.3.3.26	Radwaste
2.3.2.7	Containment Atmosphere Dilution
2.3.3.31	Control Rod Drive
2.3.3.37	Radiation Monitoring
2.4.2	Primary Containment Structures

Primary Containment Isolation System

The Primary Containment Isolation System is a plant protection system that provides timely protection against the onset and consequences of accidents involving the gross release of radioactive materials from the fuel and nuclear system process barrier. The PCIS also includes steam leak detection systems. The primary containment isolation system initiates automatic isolation of appropriate lines that penetrate the primary containment whenever monitored variables exceed pre-selected operational limits.

The system initiates isolation of the reactor vessel, isolation of piping which penetrate primary containment, and isolation of piping in selected balance of plant systems that provide potential paths for the release of radioactive materials. Primary containment isolation signals are provided by diverse and redundant safety grade equipment, isolating, in general, on low reactor level, or high drywell pressure. There are several other isolation modes in addition to the main Primary Containment Isolation System logic. For example, main steam isolation valves (MSIVs) will also close as a result of high steam flow or high steam line tunnel temperature. The primary containment ventilation system isolates on Reactor Building high radiation. The High Pressure

Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) systems have instrumentation to detect pipe breaks within their own flow paths, and to subsequently isolate the associated system.

The primary containment isolation valves and associated primary containment penetrations and piping from the systems included in FSAR Table 5.2-2 are aligned to the Primary Containment Isolation System.

The Primary Containment Isolation System is discussed in FSAR Sections 5.2.3 and 7.3.

Traversing In-Core Probe System

Appropriate isolation valves are actuated during this period to ensure containment of radioactive materials within the primary containment which might be released from the reactor during the course of the accident. In addition to the Traversing In-core Probe System isolation valves, the tubing between the isolation valves and primary containment penetration are included in the Containment System for SLR.

The Traversing In-core Probe System is discussed in FSAR Section 7.3.4.7.

Secondary Containment System

The Reactor Building, in conjunction with the Reactor/Refuel Zone Ventilation System and the Standby Gas Treatment System (up to and including the second outboard isolation valve), constitutes the secondary containment. This includes penetrations of the Reactor Building. The penetrations for piping, ventilation ducts, electrical cables, and instrument leads are sealed. The ventilation ducts are provided with valves for automatic closure when reactor building isolation is required.

The Secondary Containment System interfaces with the Reactor/Refuel Zone Ventilation System (i.e., the valves which isolate secondary containment, along with the associated ductwork and controls), which is evaluated separately. The Secondary Containment System interfaces with the Standby Gas Treatment System, which is also evaluated separately. The Reactor Building is evaluated with the Reactor Building structure, and the penetrations and doors are evaluated with Hazard Barriers and Elastomers structural commodity.

The Reactor Building completely encloses the primary containment, and essentially all of the Emergency Core Cooling systems, and houses the associated spent fuel storage pool, dryer and separator storage pool, and reactor well. The secondary containment serves as the containment during reactor refueling when the primary containment is open, and as an additional fission product barrier when the primary containment is functional.

The Secondary Containment system is discussed in FSAR Sections 5.3, 14.6, and Appendix F.7.1.

The results of screening evaluations for the following components (valves, piping, penetrations, structural steel, etc.) that are essential for secondary containment integrity are presented with the associated system's screening evaluation in the following sections of this application.

Section Number	System Name
2.3.4.1	Main Steam
2.3.4.2	Condensate/Demineralized Water
2.3.4.3	Reactor Feedwater
2.3.3.2	Auxiliary Boiler
2.3.3.4	Residual Heat Removal Service Water
2.3.3.5	Raw Cooling Water
2.3.3.6	Raw Service Water
2.3.3.7	High Pressure Fire Protection (Diesel Drive Pump)
2.3.3.8	Potable Water
2.3.3.9	Normal Ventilation
2.3.3.10	Air Conditioning
2.3.3.11	Control Air
2.3.3.12	Service Air
2.3.4.7	Gland Seal Water
2.3.3.14	Station Drainage
2.3.3.15	Sampling and Water Quality
2.3.3.16	Building Heating
2.3.3.18	Demineralizer Backwash Air
2.3.2.2	Standby Gas Treatment
2.3.3.21	Emergency Equipment Cooling Water
2.3.3.22	Reactor Water Cleanup
2.3.3.23	Reactor Building Closed Cooling Water
2.3.2.3	Reactor Core Isolation Cooling
2.3.3.24	Auxiliary Decay Heat Removal
2.3.2.4	High Pressure Coolant Injection
2.3.2.5	Residual Heat Removal
2.3.2.6	Core Spray
2.3.3.25	Containment Inerting
2.3.3.26	Radwaste
2.3.3.27	Spent Fuel Pool Cooling/Cleanup
2.3.2.7	Containment Atmosphere Dilution
2.3.3.31	Control Rod Drive

Reactor/Refuel Zone Ventilation System

The Reactor/Refuel Zone Ventilation System is divided into four ventilation zones which may be isolated independently. The refueling room which is common to the three units forms the refueling zone. The individual units below the refueling floor form the three reactor zones. The four-zone ventilation control system provides increased capability for localizing the consequences of an accident or radioactive release such that the effect may be localized in one zone while maintaining the ability to isolate the entire Reactor Building if necessary. The zone system is not an engineered safeguard, and the failure of the zone system would not prevent isolation or reduce the capacity of the Secondary Containment System.

A reactor zone is isolated upon isolation of the primary containment in that particular zone, by high radiation level in the ventilation exhaust duct leaving that particular zone, or by manual alignment. The refueling zone is always isolated when any reactor zone is isolated. The refueling zone only is isolated by a manual signal or by a high radiation signal from any of the six radiation monitors that serve the refueling zone. Upon isolation, all of the ventilation systems serving the isolated zone or zones are shut down, the ducts are isolated, and the Standby Gas Treatment System is started and begins exhausting from the isolated zone or zones.

The Reactor/Refuel Zone Ventilation System is discussed in FSAR Sections 5.3.3.2, 7.12.5, and Appendix F.7.5.

The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Maintain structural integrity. The Primary Containment System functions to prevent the release of airborne radioactive materials to the plant environment. 10 CFR 54.4(a)(1)
2. Provide pressure suppression of steam release from the nuclear system or steam turbine exhaust from the RCIC System and/or the HPCI System. The Primary Containment System functions to prevent the Primary Containment from exceeding its internal design pressure. 10 CFR 54.4(a)(1)
3. Provide secondary containment boundary. The Reactor/Refuel Zone Ventilation System includes piping, ductwork and valves that are part of the secondary containment boundary. The function of the Secondary Containment System is to provide treatment and controlled release of radioactive materials that may leak from or may be released outside of the primary containment. 10 CFR 54.4(a)(1)
4. Sense process conditions and generate signals for secondary containment isolation and Standby Gas Treatment System actuation. The Reactor/Refuel Zone Ventilation System includes instrumentation that provides signals for secondary containment isolation and Standby Gas Treatment System actuation. 10 CFR 54.4(a)(1)
5. Provide a primary containment boundary during refueling and maintenance operations. The function of the Secondary Containment System is to provide a primary envelope for radiation releases when the Primary Containment System is open such as during refueling and maintenance operations. 10 CFR 54.4(a)(1)

6. Provide reactor coolant pressure boundary. The Primary Containment Isolation System includes piping and valves that are part of the reactor coolant pressure boundary. 10 CFR 54.4(a)(1)
7. Provide primary containment boundary. The Primary Containment Isolation System includes piping and valves that are part of the primary containment boundary. 10 CFR 54.4(a)(1)
8. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The Primary Containment Isolation System includes instrumentation that provides signals for reactor vessel and primary containment isolation, various system isolations, and equipment interlocks. 10 CFR 54.4(a)(1)
9. Resist structural interactions from mechanically connected nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Reactor Building Ventilation System includes nonsafety-related components that maintain structural integrity of safety-related components. 10 CFR 54.4(a)(2)
10. Directly support a safety-related function. The Reactor Building Ventilation System includes nonsafety-related piping, valves and instruments that are relied upon to preserve the structural integrity of the Secondary Containment boundary. 10 CFR 54.4(a)(2)
11. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). The Primary Containment Isolation System is credited for reactor vessel isolation to provide reactor coolant pressure boundary. 10 CFR 54.4(a)(3)
12. Relied upon 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). The Containment System maintains the primary containment boundary, the secondary containment boundary, and is also credited to meet NFPA 805 Performance Criteria. 10 CFR 54.4(a)(3)
    - The Containment System prevents the release of radioactive materials to the plant environment.
    - Provide pressure suppression of steam release from the main steam relief valves (MSRVs) or steam turbine exhaust from the RCIC System and/or the HPCI System. Pressure suppression is required to meet the NSPC Inventory and Pressure Control performance criterion.
    - The Primary Containment System functions to prevent the Primary Containment System from exceeding its internal design pressure. Indications for drywell pressure, drywell temperature, suppression pool temperature, and suppression pool level are required to meet NSPC Process Monitoring Performance Criteria.
    - The Secondary Containment System prevents the release of radioactive materials to the environment and is required to meet the NSPC Radioactive Release Performance Criteria.
    - The Reactor/Refuel Zone Ventilation System includes piping, ductwork and valves that are part of the secondary containment boundary.
    - Reactor zone ventilation fire dampers prevent propagation of fire between fire areas.
    - The Secondary Containment System provides primary containment when any of the three Primary Containment Systems are open such as during refueling and maintenance operations and is required to meet the NSPC Radioactive Release Performance Criteria.

13. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)
    - The Primary Containment System provides the primary containment boundary to limit leakage during and following a Station Blackout.
    - The Primary Containment Isolation System is credited for reactor vessel and primary containment isolation, various system isolations, and equipment interlocks for Station Blackout.
14. Portions of this system are relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49) 10 CFR 54.4(a)(3).

<u>FSAR References</u>

Sections 5.2.3, 5.2.5, 5.3

Sections 7.3, 7.12.5

Sections 14.6, 14.12

<u>Subsequent License Renewal Boundary Drawings</u>

1-47E610-64-1-SLR

1-47E817-1-SLR

1-47E865-1-SLR

1-47E865-3-SLR

1-47E859-1-SLR

1-47E862-1-SLR

2-47E610-64-1-SLR

2-47E859-1-SLR

2-47E862-1-SLR

2-47E865-13-SLR

2-47E2847-5-SLR

2-47E2847-9-SLR

2-47E2865-12-SLR

2-47E860-1-SLR

2-47E817-1-SLR

3-47E610-64-1-SLR

3-47E817-1-SLR

3-47E859-1-SLR

3-47E862-1-SLR

3-47E865-12-SLR

3-47E3847-5-SLR

3-47E3847-9-SLR

3-47E860-1-SLR

0-47E851-1-SLR

0-47E865-11-SLR
0-47E865-15-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.2-1, Containment System.

Table 2.3.2-1, Containment System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure, Structural Support
Ducting, Ducting Components	Pressure Boundary
External Surfaces	Pressure Boundary
Fire Damper Assemblies	Fire Barrier
Heat Exchanger Components	Pressure Boundary
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.2.2-1, Containment System - Summary of Aging Management Evaluation.

2.3.2.2 Standby Gas Treatment System

Description

The Standby Gas Treatment System provides a means for minimizing the release of radioactive material from the containment to the environs by filtering and exhausting the air from any or all zones of the Reactor Building and maintaining the building at a negative pressure (such that air leakage is into, not out of, the building) during containment isolation conditions. Elevated release is assured by exhausting to the plant stack.

The Standby Gas Treatment System is a plant-shared system. The Standby Gas Treatment System consists of a suction duct system, three filter trains and blowers, and a discharge vent system. The common suction duct system takes suction from the normal ventilation exhaust duct of each of the three reactor zones and from the refueling zone independent of the normal ventilation system. Each filter train contains a moisture separator, a heater, a prefilter, an upstream High Efficiency Particulate Air (HEPA) filter, a charcoal filter, and a downstream HEPA filter. The three filter trains and blowers are arranged in parallel. The three blowers share a common discharge header that discharges to the 600-foot high plant stack. The Standby Gas Treatment System is normally in standby and starts automatically when required. The filter trains and blowers are located in the Standby Gas Treatment Building.

The Standby Gas Treatment System is discussed in FSAR Sections 5.3.3.7, 5.3.4.2, 7.12.5, 14.6, and Appendix F.7.18. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

<u>Intended Functions</u>

1. Control and treat radioactive materials released to the secondary containment. The Standby Gas Treatment System maintains a negative pressure within Reactor Building, and filters the exhaust air to reduce halogen and particulate concentrations in gases prior to their elevated release point. 10 CFR 54.4(a)(1)
2. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The Standby Gas Treatment System includes environmentally qualified electrical components. 10 CFR 54.4(a)(3)
3. Relied upon 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). The Standby Gas Treatment System is credited to meet NFPA 805 Performance Criteria. 10 CFR 54.4(a)(3).

<u>FSAR References</u>

Section 5.3.3.7

Section 3.4.2

Section 7.12.5

Section 14.6

Appendix F.7.18

<u>Subsequent License Renewal Boundary Drawings</u>

1-47E865-1-SLR

0-47E865-11-SLR

2-47E2865-12-SLR

0-47E830-1-SLR

<u>Components Subject to AMR</u>

The component types that require aging management review are indicated in the below Table 2.3.2-2, Standby Gas Treatment System.

Table 2.3.2-2, Standby Gas Treatment System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure, Structural Support
Ducting, Ducting Components	Pressure Boundary
External Surfaces	Pressure Boundary
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.2.2-2, Standby Gas Treatment System - Summary of Aging Management Evaluation.

2.3.2.3 Reactor Core Isolation Cooling System

Description

The RCIC System provides makeup water to the reactor vessel during shutdown and isolation from the main heat sink to supplement or replace the normal makeup sources and operates automatically in time to obviate any requirement for the Core Standby Cooling Systems

The RCIC System consists of a steam-driven, turbine-pump unit and associated valves and piping capable of delivering makeup water to the reactor vessel. The primary water source is from the condensate storage tank, with a backup supply of water available from the suppression pool. Delivery of water to the reactor vessel is via the feedwater system. Steam supply to the RCIC turbine is from the reactor vessel via the main steam system. The RCIC system includes a test line from the pump discharge to facilitate functional testing. A minimum-flow bypass line to the pressure suppression pool is provided for pump protection. This minimum flow bypass line has an interface with the RHR system. The exhaust steam from the turbine is directed to the suppression pool.

The RCIC components that are nonsafety-related meet the criteria of 10 CFR 54.4 (a)(2) as they include nonsafety-related fluid filled lines in the Reactor Building that have the potential for spatial interactions with safety-related SSCs and the nonsafety-related piping is mechanically connected and provide structural support to the safety-related portion of the RCIC System.

In addition, the RCIC System contains nonsafety-related components that also serve the following safety functions: 1) provide the Alternate Leakage Treatment (ALT) path from the MSIVs to the condenser that limit radioactive materials release to the environment; and 2) to preserve structural integrity of the Secondary Containment boundary to prevent a radioactive discharge to the environment.

The RCIC System is described in detail in FSAR Section 4.7. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Remove residual heat from the reactor coolant system. The RCIC system provides high pressure coolant flow to the reactor vessel. 10 CFR 54.4(a)(1)
2. Provide reactor coolant pressure boundary. The RCIC System includes piping and valves that are part of the reactor coolant pressure boundary. 10 CFR 54.4(a)(1)
3. Provide primary containment boundary. The RCIC System includes piping and valves that are part of the primary containment boundary. 10 CFR 54.4(a)(1)
4. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The RCIC System includes instrumentation that provides signals for interlocks, automatic controls, and to initiate credited manual actions. 10 CFR 54.4(a)(1)
5. Provide system pressure boundary integrity. The RCIC pump minimum flow bypass line includes piping at the RHR System interfaces that are required to maintain their pressure boundary integrity so as not to jeopardize the ability of the RHR System to perform its nuclear safety functions. 10 CFR 54.4(a)(1)

6. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The RCIC System includes nonsafety-related fluid filled lines in the Reactor Building which have the potential for spatial interaction with safety-related SSCs in the Reactor Building. 10 CFR 54.4(a)(2)
7. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. The RCIC nonsafety-related piping is mechanically connected and provide structural support to the safety-related portion of the RCIC System. 10 CFR 54.4(a)(2)
8. Directly support a safety-related function. Some the RCIC nonsafety-related components are relied upon to provide a safety-related function following a DBE, those components provide the ALT path from the MSIVs to the Condenser. 10 CFR 54.4(a)(2)
9. Directly support a safety-related function. Some of the RCIC nonsafety-related components preserve the structural integrity of the Secondary Containment boundary. 10 CFR 54.4(a)(2)
10. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). The RCIC System provides a portion of the reactor coolant pressure boundary. 10 CFR 54.4(a)(3)
11. Portions of this system are relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). This system includes environmentally qualified electrical components. 10 CFR54.4(a)(3)
12. Relied upon 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). The RCIC System maintains the reactor coolant pressure boundary and is also credited to meet NFPA 805 Performance Criteria. 10 CFR 54.4(a)(3)
13. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The RCIC System is credited for reactor vessel makeup for Station Blackout. 10 CFR 54.4(a)(3).

<u>FSAR References</u>

Sections 4.1, 4.7

Sections 5.2.3, 5.3

Sections 7.3, 7.18

<u>Subsequent License Renewal Boundary Drawings</u>

1-47E813-1-SLR

2-47E813-1-SLR

3-47E813-1-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.2-3, Reactor Core Isolation Cooling System.

Table 2.3.2-3, Reactor Core Isolation Cooling System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure, Structural Support
External Surfaces	Pressure Boundary
Heat Exchanger Components	Pressure Boundary
Piping, Piping Components	Pressure Boundary
Tanks	Pressure Boundary

The aging management review results for these components are provided in Table 3.2.2-3, Reactor Core Isolation Cooling System - Summary of Aging Management Evaluation.

2.3.2.4 High Pressure Coolant Injection System

Description

The HPCI System is provided to assure that the reactor is adequately cooled to limit fuel cladding temperature in the event of a small break in the nuclear system and loss of coolant which does not result in rapid depressurization of the reactor vessel. The HPCI System permits the nuclear plant to be shut down, while maintaining sufficient reactor vessel water inventory until the reactor vessel is depressurized. The HPCI System continues to operate until the reactor vessel pressure is below the pressure at which low pressure coolant injection operation or Core Spray System operation maintains core cooling.

The HPCI System consists of a steam turbine assembly driving a constant-flow pump assembly and system piping, valves, controls, and instrumentation. The system includes a pressurized hydraulic oil control system that also provides lubrication to the pump and turbine. The safety-related water source for the HPCI System is from the suppression pool, with a back-up supply from the nonsafety-related condensate storage tank. Delivery of water to the reactor vessel occurs via the Feedwater System. Steam supply to the HPCI turbine is from the reactor vessel via the Main Steam System. The HPCI system is equipped with a full flow test line to the condensate storage tank to facilitate functional testing. A minimum flow bypass is provided for pump protection. The exhaust steam from the turbine is discharged to the suppression pool.

The HPCI System is described in detail in FSAR Section 6.4.1. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide emergency core cooling where the equipment provides coolant directly to the reactor core. The HPCI System is an emergency core cooling system that provides high pressure coolant to the reactor vessel for small reactor coolant system breaks. The HPCI System fulfills

the objectives of the RCIC System in the event that the RCIC System is not available. 10 CFR 54.4(a)(1)

2. Provide reactor coolant pressure boundary. The HPCI System includes piping and valves that are part of the reactor coolant pressure boundary. 10 CFR 54.4(a)(1)
3. Provide primary containment boundary. The HPCI System includes piping and valves that are part of the primary containment boundary. 10 CFR 54.4(a)(1)
4. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The HPCI System includes instrumentation that provides signals for interlocks, automatic controls, and to initiate credited manual actions. 10 CFR 54.4(a)(1)
5. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The HPCI System includes nonsafety-related fluid filled lines in the Reactor Building which have the potential for spatial interaction with safety-related SSCs in the Reactor Building. 10 CFR 54.4(a)(2)
6. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. The HPCI System includes nonsafety-related components that maintain structural integrity of HPCI System with reactor coolant pressure boundary and primary containment boundary. 10 CFR 54.4(a)(2)
7. Directly support a safety-related function. Some of the HPCI nonsafety-related components are relied upon to provide a safety-related function following a DBE, those components provide the ALT path from the MSIVs to the Condenser. 10 CFR 54.4(a)(2)
8. Directly support a safety-related function. Some of the HPCI nonsafety-related components preserve the structural integrity of the Secondary Containment boundary. 10 CFR 54.4(a)(2)
9. Relied upon 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). The HPCI System maintains the reactor coolant pressure boundary and is also credited to meet NFPA 805 Performance Criteria. 10 CFR 54.4(a)(3)
10. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The HPCI System includes environmentally qualified electrical components. 10 CFR 54.4(a)(3)
11. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The HPCI System is credited for reactor vessel pressure control, reactor vessel inventory control, and decay heat removal for Station Blackout. 10 CFR 54.4(a)(3)
12. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). 10 CFR 54.4(a)(3)
    - The HPCI System maintains the reactor coolant pressure boundary for SLC injection.
    - The HPCI System is credited for reactor makeup if the feedwater system is not available.

<u>FSAR References</u>

Section 5.2.3

Section 5.3

Section 6.3

Section 6.4.1

Section 6.5
Section 7.3
Section 7.4
Section 7.8
Section 14.6

Subsequent License Renewal Boundary Drawings
0-117C2562-3-SLR
1-47E812-1-SLR
1-47E812-2-SLR
2-47E812-1-SLR
2-47E812-2-SLR
3-47E812-1-SLR
3-47E812-2-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.2-4, High Pressure Coolant Injection System.

Table 2.3.2-4, High Pressure Coolant Injection System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure, Structural Support
External Surfaces	Pressure Boundary
Heat Exchanger Components	Pressure Boundary
Piping, Piping Components • RCPB • Non-RCBP	Pressure Boundary
Tanks	Pressure Boundary

The aging management review results for these components are provided in Table 3.2.2-4, High Pressure Coolant Injection System - Summary of Aging Management Evaluation.

2.3.2.5 Residual Heat Removal System

Description

The Residual Heat Removal (RHR) System is designed for five modes of operation:

- Shutdown cooling
- Containment spray and pool cooling
- Low pressure coolant injection
- Standby Coolant
- Supplemental fuel pool cooling

The major equipment of the RHR System consists of four heat exchangers and four pumps for each unit. The equipment is connected by associated valves and piping, and the controls and instrumentation are provided for proper system operation.

The RHR pumps are sized on the basis of the flow required during the low pressure coolant injection (LPCI) mode of operation, which is the mode requiring the maximum flow rate. The heat exchangers are sized on the basis of their required duty for the pressure suppression pool cooling function.

The shutdown cooling subsystem is an integral part of the RHR system and is placed in operation during a normal shutdown and cooldown. The RHR system is typically placed in the shutdown cooling mode of operation when reactor vessel pressure has decreased sufficiently to clear the interlocks associated with the shutdown cooling suction valves. The shutdown cooling subsystem is capable of achieving reactor cooldown to maintain the reactor in cold shutdown condition.

The containment cooling subsystem provides a means for cooling the containment when operating in either the suppression pool cooling or containment spray modes. The suppression pool cooling mode provides a means to remove the reactor core decay heat and sensible heat discharged to the suppression pool in the event of a design basis accident or event. The containment cooling subsystem also provides the ability to reduce containment pressure by using the spray headers in the drywell and above the suppression pool.

The LPCI subsystem operates to restore and, if necessary, maintain the coolant inventory in the reactor vessel after a LOCA so that the core is sufficiently cooled to preclude excessive fuel clad temperature. The LPCI subsystem operates in conjunction with the high pressure coolant injection system, the automatic depressurization system, and the core spray system to achieve this goal. The LPCI subsystem is designed to reflood the reactor vessel to at least two-thirds core height and maintain this level. After the core has been flooded to this height, the capacity of one RHR pump is more than sufficient to maintain the level.

Standby coolant supply connection and RHR crossties are provided to maintain a long-term reactor core and primary containment cooling capability irrespective of primary containment integrity or operability of the RHR System associated with a given unit. The standby coolant supply connection and RHR crossties provide added long-term redundancy to the other emergency core and containment cooling systems and are designed to accommodate certain situations which, although unlikely to occur, could jeopardize the functioning of these systems.

The RHR System heat exchangers can be used to assist fuel pool cooling when required.

The RHR pump room coolers are included as part of the RHR System.

The RHR components that are nonsafety-related meet the criteria of 10 CFR 54.4(a)(2) as they include nonsafety-related fluid filled lines in the Reactor Building that have the potential for spatial interactions with safety-related SSCs and the RHR nonsafety-related piping is mechanically connected and provides structural support to the safety-related portion of the RHR System providing support to the structural integrity of the safety-related piping of the RHR.

The RHR System is described in detail in FSAR Section 4.8. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide reactor coolant pressure boundary. The RHR System provides Class 1 piping and valves which are part of the reactor coolant pressure boundary. 10 CFR 54.4(a)(1)
2. Remove residual heat from the reactor coolant system. The RHR System removes decay and sensible heat from the reactor coolant system. 10 CFR 54.4(a)(1)
3. Provide emergency core cooling where the equipment provides coolant directly to the core. The RHR System provides water from the suppression pool to be injected directly into the core region of the reactor vessel following a LOCA. 10 CFR 54.4(a)(1)
4. Provide primary containment boundary. The RHR System provides safety-related primary containment isolation capability on containment spray discharge, suppression pool suction, test return, and sample lines penetrating the primary containment. 10 CFR 54.4(a)(1)
5. Provide emergency heat removal from primary containment and provide containment pressure control. The RHR System supports maintaining the suppression pool temperature below required limits following a reactor blowdown. The RHR System also provides spray headers in the drywell and suppression pool vapor spaces to maintain internal pressure below design limits. 10 CFR 54.4(a)(1)
6. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The RHR System provides for associated actuation and system protection logic for engineered safety features operation. 10 CR 54.4(a)(1)
7. Maintain emergency temperature limits within areas containing safety-related components. The RHR System provides room coolers for the RHR pump rooms to maintain emergency temperature limits within areas containing safety-related components. 10 CFR 54.4(a)(1)
8. Ensure adequate cooling in the spent fuel pool to maintain stored fuel within acceptable temperature limits. The RHR System provides additional cooling capacity for spent fuel pool cooling. 10 CFR 54.4(a)(1)
9. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The RHR System includes nonsafety-related fluid filled piping and components in the Reactor Building which have the potential for spatial interaction with safety-related SSCs. 10 CFR 54.4(a)(2)
10. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. The RHR System includes nonsafety-related piping and components that are directly connected to RHR safety related. 10 CFR 54.4(a)(2)
11. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). The RHR System provides a portion of the reactor coolant pressure boundary. 10 CFR 54.4(a)(3)
12. Portions of this system are relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). This system includes environmentally qualified electrical components. 10 CFR 54.4(a)(3)
13. Relied upon 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). The RHR System maintains the reactor coolant pressure boundary and is also credited to meet NFPA 805 Performance Criteria. 10 CFR 54.4(a)(3)

FSAR References

Sections 4.1, 4.4, 4.8

Sections 5.2.3, 5.3

Sections 6.3, 6.4.4, 6.5

Sections 7.3, 7.4, 7.8, 7.18

Section 9.2

Sections 10.5, 10.9, 10.10, 10.17

Section 14.6

Appendix F.7.9, F.7.15, F.7.16

Subsequent License Renewal Boundary Drawings

1-47E811-1-SLR

2-47E811-1-SLR

3-47E811-1-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.2-5, Residual Heat Removal System.

Table 2.3.2-5, Residual Heat Removal System

Component Type	Passive Intended Functions
Closure Bolting • RCPB • Non-RCPB	Mechanical Closure, Structural Support
External Surfaces • Non-RCPB	Pressure Boundary
Heat Exchangers	Pressure Boundary
Piping, Piping Components • RCPB • Non-RCPB	Pressure Boundary

The aging management review results for these components are provided in Table 3.2.2-5, Residual Heat Removal System - Summary of Aging Management Evaluation.

2.3.2.6 Core Spray System

Description

The Core Spray System provides a redundant means for removal of decay heat from the core following a postulated LOCA. The system also provides a means for flooding the reactor vessel to remove decay heat from the core to support alternate shutdown cooling.

The system consists of two independent loops per unit, each with two 50 percent capacity motor driven pumps and associate piping, valves and instrumentation necessary to perform the system intended functions. The Core Spray System automatically sprays water onto the top of the fuel assemblies upon receipt of signals indicative of a LOCA. The system delivers cooling water at a sufficient flow rate to cool the core and prevent excessive fuel clad temperature. The Core Spray System initiates on the same signal as the LPCI subsystems. Both Core Spray and LPCI operate independently to fulfill the same objective. The Core Spray System is maintained in a standby condition, powered by independent safeguard buses in the electrical distribution system.

The Core Spray System provides protection to the core for large break scenarios with resultant low reactor pressure. In addition protection can be afforded for small break scenarios in which the automatic depressurization system has initiated to lower reactor vessel pressure.

The core spray pump room coolers are included in the scope of the Core Spray System.

The Core Spray System is described in detail in FSAR Section 6.4.3. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

<u>Intended Functions</u>

1. Provide emergency core cooling where the equipment provides coolant directly to the core. The Core Spray System automatically sprays water onto the top of the fuel assemblies upon receipt of signals indicative of a LOCA. 10 CFR 54.4(a)(1)
2. Provide reactor coolant pressure boundary. The Core Spray System includes piping and valves that are part of the reactor coolant pressure boundary. 10 CFR 54.4(a)(1)
3. Provide primary containment boundary. The Core Spray System includes piping and valves that are part of the primary containment boundary. 10 CFR 54.4(a)(1)
4. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The Core Spray System includes instrumentation that provides signals for interlocks, automatic controls, and to initiate credited manual actions. 10 CFR 54.4(a)(1)
5. Maintain emergency temperature limits within areas containing safety-related components. The Core Spray System includes room coolers that maintain acceptable temperatures in the core spray pump rooms during Core Spray System operation. 10 CFR 54.4(a)(1)
6. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Core Spray System includes nonsafety-related fluid filled lines in the Reactor Building which have the potential for spatial interaction with safety-related SSCs in the Reactor Building. 10 CFR 54.4(a)(2)
7. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. The Core Spray System includes nonsafety-related components that are mechanically connected to safety-related Core Spray components. 10 CFR 54.4(a)(2)
8. Directly support a safety-related function. The Core Spray System includes nonsafety-related piping and valves which preserve the structural integrity of the Secondary Containment boundary and pressure boundary interface with the condensate system ring header. 10 CFR 54.4(a)(2)
9. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram

(10 CFR 50.62). The Core Spray System provides a portion of the reactor coolant pressure boundary. 10 CFR 54.4(a)(3)

10. Portions of this system are relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). This system includes environmentally qualified electrical components.
11. Relied upon 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). The Core Spray System maintains the reactor coolant pressure boundary and is also credited to meet NFPA 805 Performance Criteria. 10 CFR 54.4(a)(3)

FSAR References

Section 4.4

Sections 5.2.3, 5.2.4, 5.3

Sections 6.3, 6.4.3

Sections 7.3, 7.4, 7.8

Section 10.10

Section 11.7

Section 14.6

Appendix F.7.9

Subsequent License Renewal Boundary Drawings

1-47E814-1-SLR

2-47E814-1-SLR

3-47E814-1-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.2-6, Core Spray System.

Table 2.3.2-6, Core Spray System

Component Type	**Passive Intended Functions**
Closure Bolting • RCPB • Non-RCPB	Mechanical Closure, Structural Support
External Surfaces • Non-RCPB	Pressure Boundary
Piping, Piping Components • RCPB • Non-RCPB	Pressure Boundary
Tanks	Pressure Boundary

The aging management review results for these components are provided in Table 3.2.2-6, Core Spray System - Summary of Aging Management Evaluation.

2.3.2.7 Containment Atmosphere Dilution System

Description

The CAD System is a safety-related standby system used following a LOCA to maintain the oxygen concentration within the containment at less than five percent by volume. The CAD System nitrogen supply tank also supplies pressurized nitrogen to the Automatic Depressurization System (ADS) MSRV accumulators.

The CAD system nitrogen supply facilities include two trains, each of which is capable of supplying nitrogen through separate piping systems to the drywell and suppression chamber. Each train includes a liquid nitrogen supply tank, an ambient vaporizer, an electric heater, a manifold with branches to each primary containment, and pressure, flow, and temperature controls. The Containment Inerting System, including the combustible gas analyzers, is evaluated separately.

The CAD System is described in FSAR Section 5.2.6. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide primary containment boundary. The CAD System includes piping and valves that are part of the primary containment boundary. The CAD nitrogen supply tank supplies pressurized nitrogen to the ADS MSRV accumulators and the reactor building to torus vacuum breaker butterfly valves. 10 CFR 54.4(a)(1)
2. Control combustible gas mixtures within the primary containment atmosphere. The CAD System provides the capability to purge the containment with nitrogen and maintain containment atmosphere at less than five percent oxygen following a LOCA. 10 CFR 54.4(a)(1)
3. Portions of this system are relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). This system includes environmentally qualified electrical components. 10 CFR 54.4(a)(3)
4. Relied upon 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). The CAD System controls combustible gas mixtures within the primary containment atmosphere and is also credited to meet NFPA 805 Performance Criteria. 10 CFR 54.4(a)(3)
5. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The CAD System is credited with being able to provide the ADS main steam safety relief valve accumulators with additional compressed gas inventory using the CAD System crosstie. 10 CFR 54.4(a)(3)

FSAR References
Section 5.2.6
Section 14.6

Subsequent License Renewal Boundary Drawings
1-47E862-1-SLR
2-47E862-1-SLR
3-47E862-1-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.2-7, Containment Atmosphere Dilution System.

Table 2.3.2-7, Containment Atmosphere Dilution System

Component Type	Passive Intended Functions
Closure Bolting • RCPB • Non-RCPB	Mechanical Closure, Structural Support
External Surfaces • Non-RCPB	Pressure Boundary
Heat Exchangers	Pressure Boundary
Piping, Piping Components • RCPB • Non-RCPB	Pressure Boundary
Tanks	Pressure Boundary

The aging management review results for these components are provided in Table 3.2.2-7, Containment Atmosphere Dilution System - Summary of Aging Management Evaluation.

2.3.3 Auxiliary Systems

The following systems are addressed in this section:

- Emergency High Pressure Makeup System (2.3.3.1)
- Auxiliary Boiler System (2.3.3.2)
- Fuel Oil System (2.3.3.3)
- Residual Heat Removal Service Water System (2.3.3.4)
- Raw Cooling Water System (2.3.3.5)
- Raw Service Water System (2.3.3.6)
- High Pressure Fire Protection (Diesel Drive Pump) System (2.3.3.7)
- Potable Water System (2.3.3.8)

- Normal Ventilation System, includes Turbine Building Ventilation System, Radwaste Ventilation System, and Diesel Generator Room Ventilation System (2.3.3.9)
- Air Conditioning System (2.3.3.10)
- Control Air System (2.3.3.11)
- Service Air System (2.3.3.12)
- CO_2 Storage, Fire Protection/Purge System (2.3.3.13)
- Station Drainage System (2.3.3.14)
- Sampling and Water Quality System (2.3.3.15)
- Building Heating System (2.3.3.16)
- Hypochlorite System (2.3.3.17)
- Demineralizer Backwash Air System (2.3.3.18)
- Standby Liquid Control System (2.3.3.19)
- Off-Gas System (2.3.3.20)
- Emergency Equipment Cooling Water System (2.3.3.21)
- Reactor Water Cleanup System (2.3.3.22)
- Reactor Building Closed Cooling Water System (2.3.3.23)
- Auxiliary Decay Heat Removal System (2.3.3.24)
- Containment Inerting System (2.3.3.25)
- Radwaste System (2.3.3.26)
- Spent Fuel Pool Cooling/Cleanup System (2.3.3.27)
- Fuel Handling and Storage System (2.3.3.28)
- Standby Diesel Generators (2.3.3.29)
- Supplemental Diesel Generator System (2.3.3.30)
- Control Rod Drive System (2.3.3.31)
- Diesel Generator Starting Air System (2.3.3.32)
- Cranes and Hoists (2.3.3.33)
- Sewage System (2.3.3.34)
- Diverse and Flexible Coping Strategies (FLEX) System (2.3.3.35)
- Security System (2.3.3.36)
- Radiation Monitoring System (2.3.3.37)
- Hardened Containment Venting System (2.3.3.38)

2.3.3.1 Emergency High Pressure Makeup System

Description

The Emergency High Pressure Makeup (EHPM) System consists of a motor driven pump unit and associated valves and piping capable of delivering makeup water to the reactor vessel. The EHPM System includes dedicated medium and low voltage electrical components to ensure EHPM system power independence from existing site power distribution to the extent practicable. The EHPM System also includes electric room ventilation fans and associated duct work. The pump takes suction from the condensate system via the bottom of the condensate storage tank (CST) and discharges into the reactor feedwater line for delivery to the reactor vessel. The EHPM system provides emergency makeup water from the CST to the reactor vessel during fire events where the fire results in the normal (e.g., reactor feedwater) and emergency (e.g., emergency core cooling systems and RCIC) methods of reactor vessel inventory control are non-functional or ineffective.

Following any reactor shutdown, steam generation continues due to heat produced by the radioactive decay of fission products. The EHPM system provides inventory to a shutdown and isolated reactor vessel to compensate for inventory loss due to boil-off and reactor coolant leakage. During fire events where the normal (e.g., reactor feedwater) and emergency (e.g., emergency core cooling systems and RCIC) methods of reactor vessel inventory control are non-functional or ineffective, the EHPM system has a makeup capacity sufficient to maintain the core in a safe and stable state. The EHPM system is manually initiated and controlled.

The EHPM System is described in FSAR Section 10.25. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Relied upon 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).
   10 CFR 54.4(a)(3)
   - This system is included in the fire protection analysis to improve risk margin for core damage frequency and large and early release frequency. The EHPM system is used pump water from the CST to the reactor to improve risk margin for the NSPC Reactor Inventory Control Performance Criteria.

FSAR References

Section 10.25

Subsequent License Renewal Boundary Drawings

1-47E819-1-SLR

2-47E819-1-SLR

3-47E819-1-SLR

1-47E865-3-SLR

2-47E865-3-SLR

3-47E865-3-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-1, Emergency High Pressure Makeup System.

Table 2.3.3-1, Emergency High Pressure Makeup System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
Ducting, Ducting Components	Pressure Boundary

Table 2.3.3-1, Emergency High Pressure Makeup System (Continued)

Component Type	Passive Intended Functions
Insulated Piping, Piping Components, Tanks	Pressure Boundary
External Surfaces	Pressure Boundary
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-1, Auxiliary Boiler System - Summary of Aging Management Evaluation.

2.3.3.2 Auxiliary Boiler System

Description

The Auxiliary Boiler System provides a supply steam for the following:

- Building heating
- HPCI and RCIC testing
- Steam seal regulator at startup
- Condenser hotwell deaeration and heating at startup (Unit 1 and Unit 3)
- Steam jet air ejector (SJAE) operation at startup
- Radwaste evaporator (in place but not generally used)
- Off-gas preheater at startup
- Nitrogen evaporator
- Sellers jet
- Pegging steam for auxiliary deaerator

The Auxiliary Boiler System nonsafety-related components include fluid filled piping which is inside the Reactor Building with the potential for spatial interactions with safety-related SSCs.

In addition, the Auxiliary Boiler System contains nonsafety-related components that also serve the following safety functions: 1) provide the Alternate Leakage Treatment (ALT) path from the MSIVs to the condenser that limits radioactive materials release to the environment; and 2) preservation of the structural integrity of the Secondary Containment boundary and prevention of radioactive discharge to the environment.

The Auxiliary Boiler System is described in FSAR Section 10.20. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Auxiliary Boiler System includes nonsafety-related fluid filled lines in the Reactor Building which have the potential for spatial interaction with safety-related SSCs in the Reactor Building. 10 CFR 54.4(a)(2)
2. Directly support a safety-related function. There are Auxiliary Boiler System nonsafety-related components that are relied upon to provide a safety-related function following a DBE. Those

components maintain the pressure boundary of the ALT path from the MSIVs to the Condenser. 10 CFR 54.4(a)(2)

3. Directly support a safety-related function. The Auxiliary Boiler System nonsafety-related components penetrate the Reactor Building and must preserve the structural integrity of the Secondary Containment boundary. 10 CFR 54.4(a)(2)

FSAR References

Section 10.20

Subsequent License Renewal Boundary Drawings

0-47E815-1-SLR

1-47E815-3-SLR

2-47E815-4-SLR

3-47E815-5-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-2, Auxiliary Boiler System.

Table 2.3.3-2, Auxiliary Boiler System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
External Surfaces	Pressure Boundary
Insulated Piping, Piping Components, Tanks	Pressure Boundary
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-2, Auxiliary Boiler System - Summary of Aging Management Evaluation.

2.3.3.3 Fuel Oil System

Description

The Fuel Oil System is a plant-shared system. The system provides fuel oil for the Standby Diesel Generators and the Auxiliary Boilers. The system includes fuel oil storage tanks and transfer equipment to supply the Standby Diesel Generators and the Auxiliary Boilers. The system also includes the piping, valves and connections to supply fuel oil from a temporary fuel oil tanker.

The Fuel Oil system consists of three interconnected, horizontal, cylindrical tanks for each diesel unit, a total of twenty-four for the eight diesel generators. The tanks are embedded in the substructure of the Standby Diesel Generator Buildings. The minimum storage capacity contains an adequate fuel supply for operating each diesel generator for seven days of post-LOCA operation. The seven day diesel generator run time is supported by meeting the Technical Specification requirements for minimum fuel oil level and fuel oil quality. Transfer pumps are provided to transfer fuel from the 7-day storage tanks to their associated diesel day tank. Each diesel has a day tank and pumps that supply the fuel injectors. The system is normally in standby and starts automatically when required to supply fuel to an operating diesel generator. Although not required to support the safety function of the diesels, each of the embedded seven-day storage tank assemblies can be supplied by either of two large nonsafety-related storage tanks or from a tank truck.

The Fuel Oil System is described in FSAR Sections 8.5.3.4 and 8.10. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide fuel oil to the Standby Diesel Generators. The Fuel Oil System provides and maintains an adequate fuel supply for operation of the Standby Diesel Generators for a period of seven days. 10 CFR 54.4(a)(1)
2. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Fuel Oil System includes nonsafety-related fluid filled lines in the Diesel Generator Building which have the potential for spatial interaction with safety-related SSCs in the Diesel Generator Building. 10 CFR 54.4(a)(2)
3. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. The Fuel Oil System includes nonsafety-related components that are directly connected to the Standby Diesel Generator System (safety-related SSCs). 10 CFR 54.4(a)(2)
4. Relied upon 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). 10 CFR 54.4(a)(3)
   - The Fuel Oil System maintains an adequate fuel supply for operation of the Standby Diesel Generator engines during the maximum-expected time interval between replenishment (seven days) and is required to meet the NSPC Vital Auxiliaries Performance Criteria.
   - The Fuel Oil System also supplies fuel to the High Pressure Fire Pump diesel engine.
5. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). Provide fuel oil to the Standby Diesel Generators. 10 CFR 54.4(a)(3)

FSAR References

Section 8.5.3.4

Section 8.10

Subsequent License Renewal Boundary Drawings

0-47E840-2-SLR

0-47E840-3-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-3, Fuel Oil System.

Table 2.3.3-3, Fuel Oil System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
External Surfaces	Pressure Boundary
Piping, Piping Components	Pressure Boundary
Tanks	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-3, Fuel Oil System - Summary of Aging Management Evaluation.

2.3.3.4 Residual Heat Removal Service Water System

Description

The RHRSW System is a plant-shared system. The RHRSW System functions to remove heat from the RHR System and Emergency Equipment Cooling Water (EECW) System components by pumping water from Wheeler Reservoir through the Residual Heat Removal (RHR) heat exchangers and Emergency Equipment Cooling Water (EECW) System components and discharges back to Wheeler Reservoir.

The RHRSW System consists of 12 pumps, with four headers and the necessary piping, valves and controls to provide cooling water to the RHR heat exchangers and EECW System components. The pumps are located in the Intake Pumping Station. The EECW System is evaluated separately. Four pairs of pumps are normally assigned to the RHR System and four additional pumps are normally assigned to the EECW System. Each of the pairs (assigned to the RHRSW System) feeds one independent RHR service water header which, in turn, feeds one RHR heat exchanger in each unit. The entire system is seismic Class I.

The RHRSW pumps take suction below the breach of Wheeler Dam and will, therefore, remain operable in the unlikely event of failure of the dam. Each pump has the capacity to supply 100 percent of the cooling water required by one RHR heat exchanger.

The RHRSW and EECW Systems have the capability of utilizing FLEX pumps to provide make-up water to the reactor vessel and spent fuel pools, Drywell Spray header, and cooling water to the RHR heat exchanger and other essential equipment such as the core spray room coolers. The FLEX connections to RHRSW headers in Intake Pump Station Rooms B and D are designed to be utilized during a Beyond Design Basis External Event condition for a loss of off-site power event and if the site Standby Diesel Generators are inoperable.

The RHRSW System is described in detail in FSAR Section 10.9. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide heat removal from safety-related heat exchangers. The RHRSW System provides cooling water flow to transfer heat from the RHR Heat Exchangers and EECW System components. 10 CFR 54.4(a)(1)

2. Provide secondary containment boundary. The RHRSW System includes piping and valves that are part of the secondary containment boundary. 10 CFR 54.4(a)(1)
3. Provide flood protection. The RHRSW System includes sump pumps in the Intake Pumping Station to provide flood protection of essential equipment located in the pump rooms. 10 CFR 54.4(a)(1)
4. Resist spatial interaction of nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The RHRSW System includes nonsafety-related fluid filled lines in the Reactor Building which have the potential for spatial interaction with safety-related SSCs in the Reactor Building. 10 CFR 54.4(a)(2)
5. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. The RHRSW System includes nonsafety-related components that maintain structural integrity of the safety-related portions of the system. 10 CFR 54.4(a)(2)
6. Directly supports a safety-related function. The RHRSW System includes nonsafety-related piping that is relied upon to preserve the Secondary Containment safety-related function. 10 CFR 54.4(a)(2)
7. Relied upon 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). The RHRSW System is credited to remove decay heat to meet NSPC Decay Heat Removal Performance Criteria. 10 CFR 54.4(a)(3)

<u>FSAR References</u>

Section 4.8

Sections 7.12.4, 7.18

Sections 10.5, 10.9, 10.10

Section 11.6

Appendix F.7.7, F.7.15, and F.7.16

<u>Subsequent License Renewal Boundary Drawings</u>

1-47E858-1-SLR

2-47E858-1-SLR

3-47E858-1-SLR

<u>Components Subject to AMR</u>

The component types that require aging management review are indicated in the below Table 2.3.3-4, Residual Heat Removal Service Water System.

Table 2.3.3-4, Residual Heat Removal Service Water System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
Heat Exchanger	Pressure Boundary, Heat Transfer
Insulated Piping, Piping Components, Tanks	Pressure Boundary
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-4, Residual Heat Removal Service Water System - Summary of Aging Management Evaluation.

2.3.3.5 Raw Cooling Water System

Description

The Raw Cooling Water (RCW) System furnishes cooling water to the following plant components:

- Turbine lube oil coolers
- Generator stator water coolers
- Generator hydrogen coolers
- Reactor feed pump turbine oil coolers
- Service and control air compressors
- SJAE precoolers
- Generator exciter air coolers
- Air conditioning condensers
- Recirculation pump Variable Frequency Drive heat exchangers
- Reactor Building Closed Cooling Water heat exchangers
- Condensate booster pump motor heat exchanger
- CRD pump speed changer oil cooler and pump thrust bearing cooler
- Other miscellaneous coolers

There are 12 main RCW System pumps, located in the Turbine Building, and they are supplied with river water from the condenser circulating water conduits of each unit. For Units 1 and 2, three pumps are required per unit and one is provided as a spare, for a total of 7 RCW pumps. For Unit 3, three pumps are required and two are provided as spares, for a total of 5 RCW pumps. All pumps discharge into a common header.

The RCW System is described in FSAR Sections 5.3 and 10.7 and Appendix F.6.5. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide pressure boundary integrity to the EECW System 10 CFR 54.4(a)(1)
2. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The RCW System includes nonsafety-related fluid filled lines in the Reactor Building which have the potential for spatial interaction with safety-related SSCs in the Reactor Building. 10 CFR 54.4(a)(2)
3. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function The RCW System includes nonsafety-related components that are directly connected and maintain structural integrity of safety related components. 10 CFR 54.4(a)(2)

4. Directly support a safety-related function. The RCW System nonsafety-related components penetrate the Reactor Building and must preserve the structural integrity of the Secondary Containment boundary. 10 CFR 54.4(a)(2)
5. Relied upon 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). 10 CFR 54.4(a)(3)
   - The RCW system provides cooling to the Condensate Pump and Condensate Booster Pump area cooling units, to the Condensate Pump motor bearings, and the Condensate Booster Pump lube oil coolers for all units. RCW supplies cooling water for the Unit 1 and Unit 2 Condensate Booster Pump motor bearings. The RCW system is needed to meet NSPC Inventory Control Performance Criteria.
   - The RCW system provides cooling to the Control Air System air compressors. The RCW system is needed to meet the NSPC Vital Auxiliaries Performance Criteria.
   - In the event of a real or spurious accident signal during a fire event, components within this system are designed and required to load shed in order to meet Performance Criteria.

<u>FSAR References</u>

Section 5.3

Section 10.7

Appendix F.6.5

<u>Subsequent License Renewal Boundary Drawings</u>

0-47E844-3-SLR

1-47E844-1-SLR

2-47E844-1-SLR

3-47E844-1-SLR

1-47E844-2-SLR

2-47E844-2-SLR

3-47E844-2-SLR

1-47E844-3-SLR

2-47E844-3-SLR

3-47E844-3-SLR

0-47E838-1-SLR

2-47E610-76-4-SLR

3-47E610-76-4-SLR

1-47E848-1-SLR

2-47E848-1-SLR

3-47E848-1-SLR

<u>Components Subject to AMR</u>

The component types that require aging management review are indicated in the below Table 2.3.3-5, Raw Cooling Water System.

Table 2.3.3-5, Raw Cooling Water System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
External Surfaces	Pressure Boundary
Heat Exchanger	Pressure Boundary, Heat Transfer
Insulated Piping, Piping Components, Tanks	Pressure Boundary
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-5, Raw Cooling Water System - Summary of Aging Management Evaluation.

2.3.3.6 Raw Service Water System

Description

The objective of the Raw Service Water (RSW) System is to supply river water for yard-watering, cooling for plant equipment which the RCW System may not conveniently serve, and to function as a keep-fill system for the raw water Fire Protection System. The RSW system supplies Condenser Circulating Water (CCW) bearing seal and lubrication water. The CCW system is required to meet the NFPA 805 Vital Auxiliaries Nuclear Safety Performance Criteria.

The RSW System furnishes water for yard-watering, cooling for miscellaneous plant equipment which require small quantities of cooling water, and functions as a keep-fill system for the raw water fire protection system. The RSW System is supplied river water from the CCW inlet conduit through a strainer section to the main RCW pump suction header for each unit. Unit 1 and Unit 2 each have one RSW pump and Unit 3 has two RSW pumps. Therefore, four pumps supply the common plant system. The pumps discharge into a distribution system common to the raw service water and fire protection systems. Two 10,000-gallon capacity storage tanks are located atop the Reactor Building. Water level in the tanks controls operation of the RSW pumps except during operation of the High Pressure Fire Protection (HPFP) pumps or when the RSW pumps are in manual with the storage tanks isolated from the system. When the HPFP pumps are operating, the RSW pumps will automatically be de-energized (unless in manual) and the RSW storage tanks will also be isolated from the system.

The RSW System is described in FSAR Section 10.8. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The RSW System includes nonsafety-related fluid filled lines in the Reactor Building which have the potential for spatial interaction with safety-related SSCs in the Reactor Building. 10 CFR 54.4(a)(2)
2. Directly support a safety-related function. The RSW System nonsafety-related components penetrate the Reactor Building and must preserve the structural integrity of the Secondary Containment boundary. 10 CFR 54.4(a)(2)

3. Relied upon 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).
   10 CFR 54.4(a)(3)
   - The RSW system provides water to function as a keep-fill system for the HPFP System.
   - The RSW system provides CCW pump bearing seal and lubricating water to support the vital auxiliaries NSPC

FSAR References

Sections 10.8, 10.10

Appendix F.6.6

Subsequent License Renewal Boundary Drawings

0-47E836-2-SLR

1-47E836-1-1-SLR

1-47E836-1-2-SLR

2-47E836-1-SLR

3-47E836-1-SLR

1-47E850-1-SLR

1-47E850-2-SLR

2-47E850-2-SLR

3-47E850-1-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-6, Raw Service Water System.

Table 2.3.3-6, Raw Water System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
Heat Exchanger	Pressure Boundary, Heat Transfer
Piping, Piping Components	Pressure Boundary
Tanks	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-6, Raw Service Water System - Summary of Aging Management Evaluation.

2.3.3.7 High Pressure Fire Protection (Diesel Driven Pump) System

Description

The objective of the HPFP System is to provide an adequate water delivery and distribution system to extinguish fires inside and outside of buildings and provide adequate fire protection for the entire plant. It supplies water for fixed water spray, pre-action sprinkler, and aqueous foam systems for selected equipment and areas in the Control Bay (which includes the control rooms) of the Reactor Buildings, the Reactor Buildings, the Turbine Buildings, the Intake Pumping Station, the Transformer Yard, Diesel Generator Buildings, and Service Buildings.

The HPFP System is a plant-shared system. The system is supplied water by three motor- driven pumps at the Intake Pumping Station and a single diesel driven pump located in a building adjacent to Gate Structure Number 2 on the cold water channel. The pumps discharge into a common header for distribution throughout the plant to hydrants, hose racks, hose connections, and water spray systems. Included in the HPFP System are detection and alarm devices that automatically initiate the system and prompt manual fire firefighting activities using the system.

The HPFP System is described in FSAR Sections 1.6.5.4 and 10.11 and Appendix F.6.9. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide secondary containment boundary. The HPFP System includes safety related components (valves) that are part of the Secondary Containment boundary.
   10 CFR 54.4(a)(1)
2. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The HPFP System includes nonsafety-related fluid filled lines in the Reactor Building which have the potential for spatial interaction with safety-related SSCs in the Reactor Buildings and Diesel Generator Buildings.
   10 CFR 54.4(a)(2)
3. Directly support a safety-related function. The HPFP System nonsafety-related components penetrate the Reactor Building and must preserve the structural integrity of the Secondary Containment boundary. 10 CFR 54.4(a)(2)
4. Relied upon 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).
   10 CFR 54.4(a)(3)
   - The HPFP System ensures adequate fire protection features are available to detect, confine, and extinguish fires occurring in any portion of the facility where NFPA 805 credited equipment or equipment in risk significant areas is located.

FSAR References

Section 1.6.5.4

Section 10.11

Appendix F.6.9

Subsequent License Renewal Boundary Drawings

0-47E850-4-SLR

0-47E850-12-SLR

0-47E836-2-SLR

1-47E850-1-SLR

1-47E850-2-SLR

1-47E850-3-SLR

1-47E850-5-SLR

1-47E850-6-SLR
1-47E850-8-SLR
1-47E850-9-SLR
1-47E850-10-SLR
1-47E836-1-1-SLR
1-47E836-1-2-SLR
2-47E836-1-SLR
2-47E850-1-SLR
2-47E850-2-SLR
2-47E850-3-SLR
2-47E850-5-SLR
2-47E850-6-SLR
2-47E850-10-SLR
3-47E836-1-SLR
3-47E850-1-SLR
3-47E850-2-SLR
3-47E850-3-SLR
3-47E850-4-SLR
3-47E850-5-SLR
3-47E850-7-SLR
3-47E850-9-SLR
3-47E850-10-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-7, High Pressure Fire Protection (Diesel Driven Pump) System.

Table 2.3.3-7, High Pressure Fire Protection (Diesel Driven Pump) System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
Fire Water Storage Tanks	Pressure Boundary
Fire Hydrants	Pressure Boundary
Halon/carbon Dioxide Fire Suppression System Piping, Piping Components	Pressure Boundary
Heat Exchanger	Pressure Boundary, Heat Transfer
Insulated Piping, Piping Components, Tanks	Pressure Boundary
Piping, Piping Components	Pressure Boundary
Sprinklers	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-7, High Pressure Fire Protection (Diesel Driven Pump) System - Summary of Aging Management Evaluation.

2.3.3.8 Potable Water System

Description

The Potable Water System is a plant-shared system which supplies potable water to various areas in the plant. This water source is supplied by the city of Athens, Alabama. Backflow preventers are installed at each cross connection to other systems to protect the potable water supply from possible contamination due to backflow.

The Potable Water System is described in FSAR Section 10.15. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Potable Water System includes nonsafety-related fluid filled components which have the potential for spatial interaction with safety-related components. 10 CFR 54.4(a)(2)
2. Directly support of a safety-related function. The Potable Water System includes nonsafety-related piping that is relied upon to preserve the Secondary Containment safety-related function. 10 CFR 54.4(a)(2)

FSAR References

Section 5.3

Section 10.15

Appendix F.6.11

Subsequent License Renewal Boundary Drawings

0-47E835-1-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-8, Potable Water System.

Table 2.3.3-8, Potable Water System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
External Surfaces	Pressure Boundary
Insulated Piping, Piping Components, Tanks	Pressure Boundary
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-8, Potable Water System - Summary of Aging Management Evaluation.

2.3.3.9 Normal Ventilation System

Description

The Ventilation System has subsystems to provide ventilation and heating for various plant buildings. Reactor Building, Turbine Building, Radwaste Building, and Diesel Generator Buildings have separate systems for year-round ventilation. The Turbine Building, Radwaste Building, and Diesel Generator Building Ventilation Systems are included in this screening evaluation of the Normal Ventilation System. The Control Bay Ventilation System is evaluated separately (Air Conditioning System). A common plant heating system serves the Reactor, Turbine, and Radwaste Buildings. The Diesel Generator Buildings are equipped with electric resistance heaters. Heating systems are evaluated separately (Building Heat System).

The Reactor Building Normal Ventilation System interfaces with the Secondary Containment System, which is evaluated separately. The Reactor Building Normal Ventilation System is isolated and operation of the Standby Gas Treatment System initiated by low reactor water level, high drywell pressure, high radiation in a Reactor Building ventilation system, or a manual signal from the Main Control Room.

The Radwaste Building Ventilation System contains air/gas filled lines which connect with safety-related and nonsafety-related SSCs. Portions of the nonsafety-related components provide direct structural support for the safety-related SSCs.

The Unit 3, 250-V Battery Room 3EB, is ventilated and maintained at a negative pressure with two redundant roof mounted exhaust fans, each with associated backdraft dampers. The Unit 1 and 2, 250-V Battery Rooms are ventilated and maintained at a negative pressure by the Control Bay Ventilation System, which is evaluated separately.

For the four 4160-V Shutdown Board Rooms of Unit 3 (3EA, 3EB, 3EC, and 3ED) and the Bus Tie Board Room, air conditioning is provided. In addition, outdoor air is available for pressurization and exhaust. The Unit 1 and 2, 4160-V Electric Board Rooms are ventilated by the Control Bay Ventilation System, which is evaluated separately.

The Normal Ventilation System (including the Turbine Building Ventilation System, Radwaste Building Ventilation System, and Diesel Generator Room Ventilation System) are described in FSAR Section 10.12. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide secondary containment boundary. The Normal Ventilation System includes piping, ductwork, and valves that are part of the secondary containment boundary. 10 CFR 54.4(a)(1)
2. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. Nonsafety-related Radwaste Building Ventilation SSCs are mechanically connected and provide structural support to the safety-related SSCs. 10 CFR 54.4(a)(2) (Radwaste Building Ventilation System Only)

3. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Diesel Generator Room Ventilation System is relied upon to be operable following a Station Blackout event. 10 CFR 54.4(a)(3)
4. Relied upon 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). 10 CFR 54.4(a)(3)
   - The Reactor Building Ventilation, Turbine Building Ventilation, and Radwaste Building Ventilation Systems prevent the release of radioactive materials to the environment and is required to meet the NSPC Radioactive Release Performance Criteria.
   - The Reactor Building Ventilation, Turbine Building Ventilation, Radioactive Waste Building Ventilation, and Diesel Generator Room Ventilation Systems Fire Dampers prevent propagation of fire between fire areas.
   - The Diesel Generator Room Ventilation System provides ventilation to the safety-related equipment in the Diesel Generator Buildings. This supports NSPC Vital Auxiliaries Performance Criteria.
   - Battery vent hoods and exhaust ducts associated with the Diesel Generator Room Ventilation System prevent combustible concentrations of hydrogen buildup.
   - In the event of a real or spurious accident signal during a fire event, components within the Normal Ventilation Systems must load shed to meet the NSPC Vital Auxiliaries Performance Criteria.

<u>FSAR References</u>

Section 5.3

Section 10.12

Appendix F.7.11

<u>Subsequent License Renewal Boundary Drawings</u>

0-47E865-2-SLR

0-47E865-6-SLR

0-47E865-8-SLR

0-47E865-11-SLR

0-47E865-16-SLR

1-47E865-1-SLR

1-47E865-3-SLR

2-47E865-3-SLR

2-47E2865-12-SLR

3-47E865-8-SLR

3-47E865-12-SLR

<u>Components Subject to AMR</u>

The component types that require aging management review are indicated in the below Table 2.3.3-9, Normal Ventilation System.

Table 2.3.3-9, Normal Ventilation System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
Ducting, Ducting Components	Pressure Boundary, Fire Barrier, Structural Support
External Surfaces	Pressure Boundary
Fire Dampers	Pressure Boundary, Fire Barrier, Structural Support
Piping, Piping Components	Pressure Boundary, Fire Barrier, Structural Support

The aging management review results for these components are provided in Table 3.3.2-9, Normal Ventilation System - Summary of Aging Management Evaluation.

2.3.3.10 Air Conditioning System

Description

The Air Conditioning System otherwise known as the Control Building Heating, Ventilating, and Air Conditioning Systems serve the three floors in the control bay and the six shutdown electrical board rooms in the Reactor Building immediately adjacent to, and normally entered from, the control bay. There are several separate subsystems serving these areas. The Control Building air conditioning is divided into eight general areas.

The HVAC subsystems provide air-conditioned ventilation for various plant areas. The HVAC Systems provide:

- Environmental control of the control bay so that personnel occupancy can be maintained in the control room during any type of accident, including events that produce radioactive and toxic gas hazards.
- Ventilation and cooling so that the temperatures of the control bay and shutdown electrical board rooms (including those in the Unit 3 Diesel Generator Building) are maintained within acceptable limits for the operation of instruments and other equipment during accidents and events.
- Battery room ventilation to prevent the buildup of explosive gases.
- Cooling of various electrical equipment rooms, e.g., computer and communications so that the temperature is maintained within acceptable limits for the operation of instruments and other equipment when required.

The Control Room Emergency Ventilation System (CREVS) processes outside air needed to provide ventilation and pressurization for the Control Room Habitability Zone (CRHZ) during isolated conditions. When the CRHZ is isolated, a fixed amount of outside air is processed through a HEPA filter bank, air heater, charcoal absorbers, and post filters. A seismically-qualified safety-related CREVS, composed of two redundant trains, is provided in the Unit 2 control bay area. This system of filtered outside air aids in positive pressurization of the CRHZ with respect to the outdoors. The CREVS is started automatically by a primary containment isolation signal or high radiation signal from the Control Building intake duct radiation monitors, or it can be started manually.

The Air Conditioning System is described in FSAR Sections 10.12 and Appendix F.7.11. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

<u>Intended Functions</u>

1. Provide centralized area for control and monitoring of nuclear safety-related equipment. The Air Conditioning System maintains environmental conditions and ensures the safety and comfort of operating personnel in the control room. The system also provides a filtered fresh air supply during adverse plant conditions. 10 CFR 54.4(a)(1)
2. Maintain temperature limits within areas containing safety-related components. The Air Conditioning System maintains environmental conditions to ensure that the operability of safety-related equipment in the control room and electric board rooms. 10 CFR 54.4(a)(1)
3. Provide secondary containment boundary. The Air Conditioning System includes piping, ductwork, and valves that are part of the Secondary Containment boundary. 10 CFR 54.4(a)(1)
4. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Air Conditioning System includes nonsafety-related fluid filled lines in the Control Bay which have the potential for spatial interaction with safety-related SSCs in the Control Bay. 10 CFR 54.4(a)(2)
5. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. The Air Conditioning System nonsafety-related piping is mechanically connected and provides structural support to the safety-related portion of the Air Conditioning System. 10 CFR 54.4(a)(2)
6. Directly supports a safety-related function. The Air Conditioning System nonsafety-related components penetrate the Reactor Building and must preserve the structural integrity of the Secondary Containment boundary. 10 CFR 54.4(a)(2)
7. Portions of this system are relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). This system includes environmentally qualified electrical components. 10 CFR 54.4(a)(3)
8. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Air Conditioning System maintains environmental conditions and ensures the safety and comfort of operating personnel in the control room. 10 CFR 54.4(a)(3)
9. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Air Conditioning System maintains environmental conditions to ensure that the operability of safety-related equipment in the control room and electric board rooms. 10 CFR 54.4(a)(3)
10. Relied upon 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). 10 CFR 54.4(a)(3)
    - Provides cooling and pressurization of the Control Bay Mechanical Equipment Rooms. The system also recirculates air conditioning of the Main Control Rooms, Auxiliary

Instrument Rooms, Battery Board Rooms, Relay Room, essential MG Set Rooms, and the Reactor Building Board Rooms of Units 1, 2, and 3. The system also provides a filtered fresh air supply during adverse plant conditions. The Air Conditioning system is needed to meet NSPC Vital Auxiliaries Performance Criteria.

- Control Bay HVAC Fire Dampers prevent propagation of fire between fire areas.
- In the event of a real or spurious accident signal during a fire event, components within the Air Conditioning System may load shed to meet the NSPC Vital Auxiliaries Performance Criteria.

<u>FSAR References</u>

Section 10.12

Appendix F.7.11

<u>Subsequent License Renewal Boundary Drawings</u>

0-47E843-1-SLR

0-47E865-2-SLR

0-47E865-4-SLR

0-47E865-6-SLR

0-47E865-15-SLR

0-47E866-3-SLR

0-47E866-9-SLR

0-47E931-3-SLR

0-47E931-6-SLR

0-47E931-10-SLR

1-47E856-2-SLR

1-47E1865-4-SLR

1-47E1847-6-SLR

2-47E2865-4-SLR

3-47E859-2-SLR

3-47E865-4-SLR

3-47E865-8-SLR

3-47E866-5-SLR

3-47E866-7-SLR

3-47E931-6-SLR

3-47E3865-4-SLR

<u>Components Subject to AMR</u>

The component types that require aging management review are indicated in the below Table 2.3.3-10, Air Conditioning System.

Table 2.3.3-10, Air Conditioning System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
Ducting, Ducting Components	Pressure Boundary, Fire Barrier, Structural Support
External Surfaces	Pressure Boundary, Fire Barrier
Fire Damper	Pressure Boundary, Fire Barrier, Structural Support
Heat Exchangers	Pressure Boundary, Heat Transfer
Insulated Piping, Piping Components, Tank	Pressure Boundary, Structural Support
Piping, Piping Components	Pressure Boundary, Structural Support

The aging management review results for these components are provided in Table 3.3.2-10, Air Conditioning System - Summary of Aging Management Evaluation.

2.3.3.11 Control Air System

Description

The Control Air and Drywell Control Air System provides clean, dry, oil free compressed air or nitrogen (Drywell Control Air portion only) as motive force for numerous plant components during normal and post-accident operations. The Control Air portion supplies compressed air to various users throughout the plant except for user locations inside the drywell which is supplied compressed nitrogen taken from the containment inerting system and delivered by Drywell Control Air portions of the system.

The Control Air System provides:

- Motive power for numerous plant components during normal operations
- Post-accident motive power to the MSIV and the MSRVs for reactor vessel overpressure relief protection, and reactor vessel depressurization including the ADS function
- Post-accident motive power to torus vacuum breaker valves

Each unit has a separate compressed nitrogen system for its primary containment. The primary containment system for each unit consists of two compressors that take suction from the primary containment atmosphere and supply components in the primary containment. The Primary Containment System normally operates and isolates post accident. Post accident and post event motive force for primary containment components is provided by accumulators and, long term, by manually initiated interconnections with the CAD System or bottled nitrogen.

The Control Air System has five air compressors that are connected to a common discharge header. The common discharge header supplies an air dryer in each unit that then discharges into a unit header that supplies all unit loads. Valving allows each unit header to be connected to the adjacent unit's header. The system is normally operating. Essential components that are actuated by this portion of the control air system will fail to their required post accident configuration upon loss of control air. In some cases (such as the outboard MSIVs), an accumulator is provided to boost the accident actuation.

The Control Air System is described in FSAR Section 10.14. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide motive power to safety-related components. The Control Air System provides compressed air to accumulators to assure the ADS MSRVs will be held open, and the inboard MSIVs may be closed following control air failure. The Control Air System also provides compressed air to accumulators to assure the outboard MSIVs may be closed. 10 CFR 54.4(a)(1)
2. Provide primary containment boundary. The Control Air System includes piping and valves that are part of the primary containment boundary. 10 CFR 54.4(a)(1)
3. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. The Control Air System nonsafety-related piping is mechanically connected and provides structural support to the safety-related portion of the Control Air System. 10 CFR 54.4(a)(2)
4. Portions of this system are relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). This system includes environmentally qualified electrical components. 10 CFR 54.4(a)(3)
5. Relied upon 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). 10 CFR 54.4(a)(3)
   - The Control Air System provides air to several air operated valves required for safe shutdown, including valves in the main flow paths and valves that must close to prevent flow diversion to meet NSPC Reactor Inventory Control Performance Criteria.
   - The Control Air System is a support system for systems required to meet the NSPC Vital Auxiliaries Performance Criteria.
6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). Provide motive force for operating MSRVs. 10 CFR 54.4(a)(3)

FSAR References

Section 5.2.3.7

Section 10.14

Appendix F.6.3

Subsequent License Renewal Boundary Drawings

0-47E847-1-SLR

0-47E847-2-SLR

0-47E847-3-SLR

0-47E847-4-SLR

0-47E847-1-SLR

0-47E847-5-SLR
1-47E1847-1-SLR
1-47E1847-2-SLR
1-47E1847-3-SLR
1-47E1847-4-SLR
1-47E1847-5-SLR
1-47E1847-6-SLR
1-47E1847-7-SLR
1-47E1847-8-SLR
1-47E1847-9-SLR
1-47E1847-10-SLR
1-47E1847-12-SLR
1-47E1847-13-SLR
1-47E610-32-2-SLR
2-47E2847-1-SLR
2-47E2847-2-SLR
2-47E2847-3-SLR
2-47E2847-4-SLR
2-47E2847-5-SLR
2-47E2847-6-SLR
2-47E2847-7-SLR
2-47E2847-8-SLR
2-47E2847-9-SLR
2-47E2847-10-SLR
2-47E610-32-2-SLR
3-47E3847-1-SLR
3-47E3847-2-SLR
3-47E3847-3-SLR
3-47E3847-4-SLR
3-47E3847-5-SLR
3-47E3847-6-SLR
3-47E3847-7-SLR
3-47E3847-8-SLR
3-47E3847-9-SLR
3-47E3847-10-SLR
3-47E610-32-2-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-11, Control Air System.

Table 2.3.3-11, Control Air System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
Heat Exchangers	Pressure Boundary, Heat Transfer
Piping, Piping Components	Pressure Boundary, Structural Support

The aging management review results for these components are provided in Table 3.3.2-11, Control Air System - Summary of Aging Management Evaluation.

2.3.3.12 Service Air System

Description

The Service Air System is a plant-shared system. The Service Air System consists of two air compressors located in the turbine building and associated piping that extends throughout the plant including into the reactor buildings.

The Service Air System provides pressurized air to:

- Hose connections throughout the plant and yard
- Miscellaneous equipment in the SLC System, Amertap Condenser Tube Cleaning System (subsystem of the CCW System), Condensate Demineralizer Air Surge System, and the Radwaste System

The Service Air System is described in FSAR Section 10.14. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Directly support a safety-related function. The Service Air System includes nonsafety-related piping that is relied upon to preserve the structural integrity of the Secondary Containment safety-related function. 10 CFR 54.4(a)(2)
2. Relied upon 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). 10 CFR 54.4(a)(3).
    - The Service Air System is a backup to the Control Air System which is a support system for systems required to meet the NSPC Vital Auxiliaries Performance Criteria.

FSAR References

Sections 5.3

Section 10.14

Appendix F.6.3

Subsequent License Renewal Boundary Drawings

0-47E845-1-SLR

0-47E845-2-SLR

0-47E845-4-SLR
0-47E845-5-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-12, Service Air System.

Table 2.3.3-12, Service Air System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
Insulated Piping, Piping Components, Tanks	Pressure Boundary
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-12, Service Air System - Summary of Aging Management Evaluation.

2.3.3.13 CO_2 Storage, Fire Protection/Purge System

Description

The primary function of the CO_2 Storage, Fire Protection/Purging (CO_2/FP) System is to mitigate the consequences of a fire in protected areas such as the Diesel Generator (DG) buildings and control bays. In addition to the primary function, the CO_2/FP system supplies CO_2 for purging hydrogen from the main generator.

The CO_2/FP System is a fire suppression system contain electrical, lubricating oil, or fuel oil components. Units 1 and 2 share a system that includes a 17-ton storage tank. Unit 3 has a separate system with a 6-ton tank. The system is normally in standby and initiates automatically when required. When initiated, ventilation systems that could reduce the effectiveness of the CO_2 discharge are isolated. Detection and alarm devices that automatically initiate the system or would prompt manual fire firefighting activities are included in the CO_2/FP System.

The CO_2/FP system is a nonsafety-related system designed not to inadvertently initiate during a shutdown after the applicable DBEs. Release of CO_2 into the control bays would adversely affect manual operation of safety-related equipment and habitability in the protected rooms as well as cause temperature buildup due to HVAC System isolation. Release of CO_2 into the diesel generator compartments would cause sealing of the compartments and possible overheating of the diesel generator rooms because of inadequate ventilation. The prevention of overheating of the diesel generator rooms is a safety-related protective function of the CO_2/FP System.

The CO_2/FP System is described in FSAR Section 1.6.5.4 and Appendices F.6.9 and F.7.6. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Directly support a safety-related function. The CO_2/FP System nonsafety-related components are relied upon to not inadvertently release CO_2 in the diesel generator rooms and control bays. 10 CFR 54.4(a)(2)
2. Relied upon 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). 10 CFR 54.4(a)(3)
   - The CO_2/FP System is to mitigate the consequences of a fire in protected areas such as the Diesel Generator Building and control bay.
   - In the event of a real or spurious accident signal during a fire event, components within this system are designed and required to load shed in order to meet the NSPC Vital Auxiliaries Performance Criteria.

FSAR References

Section 1.6.5.4

Section 10.11

Section 13.4.4.16

Appendices F.6.9, and F.7.6

Subsequent License Renewal Boundary Drawings

0-47E843-1-SLR

3-47E843-2-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-13, CO_2 Storage, Fire Protection/Purging System.

Table 2.3.3-13, CO_2 Storage, Fire Protection/Purging System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
Ducting, Ducting Components	Pressure Boundary
External Surfaces	Pressure Boundary
Insulated Piping, Piping Components, Tanks	Pressure Boundary
Piping, Piping Components	Pressure Boundary
Tanks	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-13, CO_2 Storage, Fire Protection/Purging System - Summary of Aging Management Evaluation.

2.3.3.14 Station Drainage System

Description

The Station Drainage System is a plant-shared system. The Station Drainage System collects, processes, stores, and disposes of non-radioactive liquid waste.

The Station Drainage System is described in FSAR Section 10.16. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Station Drainage System includes nonsafety-related fluid filled components in the Reactor Buildings and Diesel Generator Buildings which have the potential for spatial interaction with safety-related components. 10 CFR 54.4(a)(2)
2. Directly support of a safety-related function. The Station Drainage System includes nonsafety-related piping that is relied upon to preserve the Secondary Containment safety-related function. 10 CFR 54.4(a)(2)

FSAR References
Sections 10.16

Subsequent License Renewal Boundary Drawings
0-47E851-1-SLR
0-47E852-3-SLR
0-47E851-4-SLR
1-47E852-1-SLR
2-47E852-1-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-14, Station Drainage System.

Table 2.3.3-14, Station Drainage System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
External Surfaces	Pressure Boundary
Insulated Piping, Piping Components, Tanks	Pressure Boundary
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-14, Station Drainage System - Summary of Aging Management Evaluation.

2.3.3.15 Sampling and Water Quality System

Description

The Sampling and Water Quality System provides the capability to obtain representative samples for testing to obtain data. The data is used to evaluate the performance of the plant, equipment, and systems during normal plant operations. Water samples can be obtained from the RWCU, Main Steam, Condensate, Feedwater, Radwaste, Fuel Pool Cooling, Reactor Building Closed Cooling Water, RHRSW, and various auxiliary systems. Gas samples can be obtained from SJAEs, the Off-Gas System, and the main stack.

Using a post accident sample subsystem, representative samples of reactor coolant, torus liquid, drywell atmosphere, torus atmosphere, and secondary containment atmosphere can be obtained after a LOCA to guide post-LOCA actions.

Portions of the Sampling and Water Quality System contain components that interface with systems in the reactor building, including RWCU, RHR, and RHRSW. Other portions of the system interface with the Reactor Recirculation System and the Reactor Building Closed Cooling Water System in the primary containment.

The Sampling and Water Quality System includes non-safety-related fluid and gas filled components (piping, tanks, heat exchangers, etc.) in the Reactor Building which have the potential for spatial interaction with safety-related components. Also, non-safety-related Sampling and Water Quality System piping is mechanically connected to other same system safety-related piping. Non-safety-related Sampling and Water Quality piping penetrates the Primary and Secondary Containment boundaries.

The Sampling and Water Quality System is described in FSAR Sections 10.17 and 10.21. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide primary containment boundary. The Sampling and Water Quality System includes piping and valves that are part of the primary containment boundary. 10 CFR 54.4(a)(1)
2. Provide system pressure boundary integrity. The Sampling and Water Quality System includes piping and components that interface with the RWCU, RHR, RHRSW, Reactor Recirculation and the Reactor Building Closed Cooling Water Systems that are required to maintain their pressure boundary integrity so as not to jeopardize the ability of those systems to perform their nuclear safety functions. 10 CFR 54.4 (a)(1)
3. Provide reactor coolant pressure boundary. The Sampling and Water Quality System includes piping and valves that are part of the reactor coolant pressure boundary. 10 CFR 54.4 (a)(1)
4. Resist spatial interaction of non-safety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Sampling and Water Quality System includes non-safety related fluid filled lines in the Reactor Building which have the potential for spatial interaction with safety-related SSCs in the Reactor Building. 10 CFR 54.4(a)(2)
5. Resist structural interactions from mechanically connected non-safety related piping that could prevent satisfactory accomplishment of a safety-related function. The Sampling and

Water Quality System includes non-safety related components that maintain structural integrity of the safety-related portions of the system. 10 CFR 54.4(a)(2)

6. Directly support a safety-related function. The Sampling and Water Quality System includes non-safety related piping and valves that are relied upon to preserve the structural integrity of the Secondary Containment boundary. 10 CFR 54.4(a)(2)
7. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). The Sampling and Water Quality System provides a portion of the reactor coolant pressure boundary. 10 CFR 54.4(a)(3)
8. Portions of this system are relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). This system includes environmentally qualified electrical components. 10 CFR 54.4(a)(3)

<u>FSAR References</u>

Sections 10.17, 10.21

<u>Subsequent License Renewal Boundary Drawings</u>

0-105E3156-1-SLR
1-47E610-43-1-SLR
1-47E610-43-2-SLR
1-47E610-43-3-SLR
1-47E610-43-5-SLR
1-47E867-3-SLR
2-47E610-43-1-SLR
2-47E610-43-2-SLR
2-47E610-43-3-SLR
2-47E610-43-6-SLR
2-47E867-3-SLR
3-47E610-43-1-SLR
3-47E610-43-2-SLR
3-47E610-43-3-SLR
3-47E610-43-6-SLR
3-47E610-43-6A-SLR
3-47E844-2-SLR
3-47E867-3-SLR

<u>Components Subject to AMR</u>

The component types that require aging management review are indicated in the below Table 2.3.3-15, Sampling and Water Quality System.

Table 2.3.3-15, Sampling and Water Quality System

Component Type	Passive Intended Functions
Class 1 Valve Bodies And Bonnets	Pressure Boundary
Closure Bolting	Mechanical Closure
Heat Exchangers	Pressure Boundary, Heat Transfer
Insulated Piping, Piping Components, Tanks	Pressure Boundary
Piping, Piping Components	Pressure Boundary
Reactor Coolant Pressure Boundary Components	Pressure Boundary
Reactor Coolant System Components: Components defined as ASME Section XI components (e.g., reactor coolant pressure boundary components, core support structure components, ASME Class 2 or 3 components, including associated pressure-retaining welds) not managed by other AMR line items in GALL-SLR Chapter IV	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-15, Sampling and Water Quality System - Summary of Aging Management Evaluation.

2.3.3.16 Building Heating System

Description

The Building Heating System maintains required temperatures for equipment protection and personnel comfort during the winter months. The Building Heating System is a plant-shared system. The Building Heating System is a forced hot water system that operates as required to maintain a minimum temperature of 55 degrees F in various plant buildings including the reactor building. The hot water is heated by the Auxiliary Boiler System and preheats building intake air. The nonsafety-related fluid filled piping in the Reactor Building has the potential for spatial interaction with safety-related components. Additionally, nonsafety-related Building Heating System piping penetrates the Secondary Containment boundary.

The Building Heating System is described in FSAR Section 10.12.5. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Building Heating System includes nonsafety-related liquid filled piping in the Reactor Building which has the potential for spatial interaction with safety-related components. 10 CFR 54.4(a)(2)
2. Directly support a safety-related function. The Building Heating System includes nonsafety-related piping and valves that are relied upon to preserve the Secondary Containment safety-related function. 10 CFR 54.4(a)(2)

3. Relied upon 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).
   10 CFR 54.4(a)(3)
   - In the event of a real or spurious accident signal during a fire event, components within the Building Heating System are designed and required to load shed in order to meet the NSPC Vital Auxiliaries Performance Criteria.

FSAR References

Section 5.3.3.6

Section 10.12.5

Subsequent License Renewal Boundary Drawings

0-47E866-1-SLR

0-47E866-2-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-16, Building Heating System.

Table 2.3.3-16, Building Heating System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
External Surfaces	Pressure Boundary
Heat Exchanger	Pressure Boundary, Heat Transfer
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-16, Building Heating System - Summary of Aging Management Evaluation.

2.3.3.17 Hypochlorite System

Description

The Hypochlorite System, also called the Raw Water Chemical Treatment System, prevents bio-fouling of systems (including the EECW and RHRSW Systems) that use water from Wheeler Reservoir by providing the capability of injecting a biocide into the fluid stream.

Hypochlorite System piping and components at the RHRSW and EECW System interfaces are required to maintain their pressure boundary so as not to jeopardize the ability of the RHRSW and EECW Systems to perform their nuclear safety functions.

The Hypochlorite System is not described in the FSAR. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide pressure boundary integrity. The Hypochlorite System includes piping and components at the RHRSW and EECW System interfaces that are required to maintain their pressure boundary integrity so as not to jeopardize the ability of the RHRSW and EECW Systems to perform their nuclear safety functions. 10 CFR 54.4(a)(1)
2. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Hypochlorite System includes nonsafety-related fluid filled lines in the Intake Pumping Station which have the potential for spatial interaction with safety-related SSCs in the Intake Pumping Station. 10 CFR 54.4(a)(2)
3. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. The Hypochlorite System nonsafety-related piping is mechanically connected and provide structural support to the safety-related portion of the Hypochlorite System. 10 CFR 54.4(a)(2)

FSAR References

None

Subsequent License Renewal Boundary Drawings

0-47E839-5-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-17, Hypochlorite System.

Table 2.3.3-17, Hypochlorite System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
Piping, Piping Components	Pressure Boundary, Structural Support

The aging management review results for these components are provided in Table 3.3.2-17, Hypochlorite System - Summary of Aging Management Evaluation.

2.3.3.18 Demineralizer Backwash Air System

Description

The Demineralizer Backwash Air System supplies a high volume of low pressure air for backwashing plant demineralizers. The system is a plant-shared system that has two compressors located in the turbine building. The system supplies the condensate demineralizers in the turbine building and penetrates secondary containment to supply the RWCU and fuel pool cooling demineralizers in the Reactor Building. The system is normally in standby and is operated manually when required for backwashing demineralizers. The Demineralizer Backwash Air System includes nonsafety-related piping and valves that are relied upon to preserve structural integrity for the safety-related function of Secondary Containment.

The Demineralizer Backwash Air System is discussed in FSAR Section 5.3.3. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Directly support a safety-related function. The Demineralizer Backwash Air System includes nonsafety-related piping and valves in the Reactor Building that are relied upon to preserve structural integrity for the safety-related function of Secondary Containment.
   10 CFR 54.4(a)(2)

FSAR References

Section 5.3.3

Subsequent License Renewal Boundary Drawings

0-47E846-1-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-18, Demineralizer Backwash Air System.

Table 2.3.3-18, Demineralizer Backwash Air System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
External Surfaces	Pressure Boundary
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-18, Demineralizer Backwash Air System - Summary of Aging Management Evaluation.

2.3.3.19 Standby Liquid Control System

Description

The purpose of the SLC System is to provide a backup method, which is independent of the control rods, to make the reactor subcritical over its full range of operating conditions and provide sufficient buffering agent to maintain the suppression pool pH at or above 7.0 following a DBA LOCA involving fuel damage. Making the reactor subcritical is essential to permit the nuclear system to cool to the point where corrective actions can be carried out. Maintaining the suppression pool pH at or above 7.0 following a LOCA involving fuel damage supports the LOCA radiological dose analyses that do not consider the re-evolution of iodine to the containment atmosphere.

The system is designed to make the reactor subcritical from rated power to a cold shutdown at any time in core life. The reactivity compensation provided will reduce reactor power from rated to the after-heat level and allow cooling the nuclear system to normal temperature with the control rods remaining withdrawn in the rated power pattern. It includes the reactivity gains due to complete decay of the rated power xenon inventory. It also includes the positive reactivity effects from eliminating steam voids, changing water density from hot to cold, reduced Doppler effect in uranium, reduction of neutron leakage from the boiling to cold condition, and decreasing control rod worth as the moderator cools.

The system consists of a boron solution tank, a test water tank, two positive-displacement pumps, two explosive-actuated valves, and associated local valves and controls. They are mounted in the Reactor Building outside the primary containment. The liquid is piped into the reactor vessel via the differential pressure and liquid control line and discharged near the bottom of the core lower support plate through a standpipe so it mixes with the cooling water rising through the core.

The SLC System is described in FSAR Section 3.8. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide reactor coolant pressure boundary. The SLC System includes piping and valves that are part of the reactor coolant pressure boundary. 10 CFR 54.4(a)(1)
2. Provide primary containment boundary. The SLC System includes piping and valves that are part of the primary containment boundary. 10 CFR 54.4(a)(1)
3. Resist spatial interaction of nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The SLC System includes nonsafety-related fluid filled lines in the Reactor Building which have the potential for spatial interaction with safety-related SSCs in the Reactor Building. 10 CFR 54.4(a)(2)
4. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. The SLC System includes nonsafety-related components that maintain structural integrity of SLC mechanical connections with reactor coolant pressure boundary and primary containment boundary. 10 CFR 54.4(a)(2)
5. Directly support a safety-related function. The SLC system is relied upon for the safety-related function of maintaining pH in the suppression pool above 7.0 in the event of a DBA LOCA by injecting a buffering agent to the Reactor Vessel. 10 CFR 54.4(a)(2)
6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). The SLC System the reactor coolant pressure boundary for SLC injection. 10 CFR 54.4(a)(3)
7. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). The SLC System injects sodium pentaborate solution into the reactor to achieve shutdown for mitigation of an ATWS. 10 CFR 54.4(a)(3)
8. Relied upon 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). 10 CFR 54.4(a)(3)

- The SLC System is included in the NFPA 805 analyses only for potential spurious operation causing credited EDG overload to demonstrate the NSPC Vital Auxiliaries Performance Criteria is met.
- Provide reactor coolant pressure boundary. The SLC System includes piping and valves that are part of the reactor coolant pressure boundary.

FSAR References

Section 3.8

Section 7.19

Appendix N

Subsequent License Renewal Boundary Drawings

1-47E854-1-SLR

2-47E854-1-SLR

3-47E854-1-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-19, Standby Liquid Control System.

Table 2.3.3-19, Standby Liquid Control

Component Type	Passive Intended Functions
Class 1 Piping, Fittings and Branch Connections < NPS 4	Pressure Boundary
Closure Bolting	Mechanical Closure
External Surfaces	Pressure Boundary
Insulated Piping, Piping Components, Tanks	Pressure Boundary
Piping, Piping Components	Pressure Boundary
Reactor Coolant Pressure Boundary Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-19, Standby Liquid Control System - Summary of Aging Management Evaluation.

2.3.3.20 Off-Gas System

Description

The Off-Gas System includes subsystems that process and dispose of the gases produced during normal operation from the main condenser SJAEs, the startup condenser vacuum pumps, the condensate drain tank vent, and the steam packing exhauster. The Off-Gas System includes dilution fans and stack cubicle exhaust fans that provide dilution air for the main stack. One Off-Gas System is provided for each unit. The gases are processed to minimize the radioactive release and then are routed to the plant stack for dilution and elevated release to the atmosphere. The Standby Gas Treatment System discharges into the Off-Gas System and routed to the plant stack. Backdraft dampers limit the amount of a ground level radioactive release during accidents that require operation of the Standby Gas Treatment System.

The Off-Gas System is described in FSAR Sections 9.5 and 11.4. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide system pressure boundary integrity. The Off-Gas System includes piping and components including backdraft dampers that interface with the Standby Gas Treatment System that are required to maintain their pressure boundary integrity so as not to jeopardize the ability of the Standby Gas Treatment System to perform its nuclear safety functions. 10 CFR 54.4(a)(1)
2. Sense process conditions and generate signals for automatic closure of back-draft prevention dampers. The Off-Gas System includes instrumentation that provides signals for automatic closure of back-draft prevention dampers to prevent back flow and potential ground level release of radiation during a design basis accident or event. 10 CFR 54.4(a)(1)
3. Resist structural interactions from mechanically connected nonsafety-related ductwork that could prevent satisfactory accomplishment of a safety-related function. The Off-Gas System includes nonsafety-related ductwork that maintain structural integrity of safety-related Off-Gas System components. 10 CFR 54.4(a)(2)
4. Resist spatial interaction of nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Off-Gas System includes nonsafety-related fluid filled lines in the Radwaste Building which have the potential for spatial interaction with safety-related SSCs in the Radwaste Building. 10 CFR 54.4(a)(2)
5. Relied upon 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). 10 CFR 54.4(a)(3)
   - In the event of a real or spurious accident signal during a fire event, components within the Off-Gas System are designed and required to load shed in order to meet the NSPC Vital Auxiliaries Performance Criteria.

FSAR References

Section 5.3.3

Sections 7.12.2, 7.12.3

Section 9.5

Section 11.4

Section 14.6.2.8

Appendix F.7.14

Subsequent License Renewal Boundary Drawings

0-47E830-1-SLR

0-47E830-9-SLR

1-47E809-2-SLR

1-47E809-3-SLR

2-47E809-2-SLR

2-47E809-3-SLR
2-47E809-4-SLR
3-47E809-2-SLR
3-47E809-3-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-20, Off-Gas System.

Table 2.3.3-20, Off-Gas System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
Ducting, Ducting Components	Pressure Boundary
External Surfaces	Pressure Boundary
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-20, Off-Gas System - Summary of Aging Management Evaluation.

2.3.3.21 Emergency Equipment Cooling Water System

Description

The EECW System provides cooling water to equipment that is essential for safe shutdown. The EECW System also provides backup cooling water supply to the Reactor Building Closed Cooling Water System heat exchangers.

The RHRSW System supplies water to the EECW System. The RHRSW System is evaluated separately. The EECW System is a plant-shared system. The EECW System has two headers that use dedicated RHRSW pumps to supply water from Wheeler Reservoir to heat exchangers cooling the following equipment: EDG engine coolers, Core Spray pump room coolers, RHR pump seal coolers and room coolers, Control Bay chillers, hydrogen and oxygen containment gas analyzers, and Electric Board Room chillers. Four pumps from the RHRSW System are assigned to the EECW System and are paired, with one pair serving each of the two EECW headers. If necessary, one of each pair of pumps normally assigned to the RHRSW System can be manually realigned to the EECW System.

The EECW System is described in FSAR Section 10.10. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provides heat removal from safety-related heat exchangers. The EECW System provides cooling water to transfer heat from safety-related heat exchangers. 10 CFR 54.4(a)(1)

2. Sense process conditions and generate signals to support accomplishment of a safety-related function. The EECW System includes instrumentation that provides a valve position interlock signal for auto-start of RHRSW pumps. 10 CFR 54.4(a)(1)
3. Provide secondary containment boundary. The EECW System includes piping and valves that are part of the secondary containment boundary. 10 CFR 54.4(a)(1)
4. Resist spatial interaction of nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The EECW System includes nonsafety-related fluid filled lines in the Reactor Building which have the potential for spatial interaction with safety-related SSCs in the Reactor Building. 10 CFR 54.4(a)(2)
5. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. The EECW System includes nonsafety-related components that maintain structural integrity of the safety-related portions of the system. 10 CFR 54.4(a)(2)
6. Directly supports a safety-related function. The EECW System nonsafety-related components penetrate the Reactor Building and must preserve the structural integrity of the Secondary Containment boundary. 10 CFR 54.4(a)(2)
7. Portions of this system are relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). This system includes environmentally qualified electrical components. 10 CFR 54.4(a)(3)
8. Relied upon 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). 10 CFR 54.4(a)(3)
    - The EECW System supports the LPCI mode of RHR and Core Spray which are needed to meet NSPC Reactor Inventory Control Performance Criteria.
    - The EECW System supports the suppression pool cooling mode, LPCI mode during alternate shutdown cooling, and the shutdown cooling mode of the RHR system which is needed to meet the Decay Heat Removal Performance Criteria.
    - The EECW System supports the drywell spray mode of RHR which is needed to meet the NSPC Vital Auxiliaries Performance Criteria.
    - The EECW System is required to meet the Vital Auxiliaries Performance Criteria.
    - The EECW System supports the Control Bay HVAC and the Electric Board Room Chillers, which are needed to meet the NSPC Vital Auxiliaries Performance Criteria.
    - The EECW System supports the EDGs, which are support systems needed to meet NSPC Vital Auxiliaries Performance Criteria.
    - The EECW System serves as a backup to the RCW System for Control Air components, which is needed for the NSPC Vital Auxiliaries Performance Criteria.
9. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The EECW System provides cooling water to transfer heat from safety-related heat exchangers for equipment credited for a Station Blackout. 10 CFR 54.4(a)(3)

FSAR References

Section 5.3

Section 7.18

Sections 10.5, 10.10
Appendix F.7.7 and F.7.17

Subsequent License Renewal Boundary Drawings
1-47E859-1-SLR
2-47E859-1-SLR
3-47E859-1-SLR
3-47E859-2-SLR
3-47E866-7-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-21, Emergency Equipment Cooling Water System.

Table 2.3.3-21, Emergency Equipment Cooling Water System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
Heat Exchangers	Pressure Boundary, Heat Transfer
Insulated Piping, Piping Components, Tanks	Pressure Boundary
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-21, Emergency Equipment Cooling Water System - Summary of Aging Management Evaluation.

2.3.3.22 Reactor Water Cleanup System

Description

The RWCU System maintains high reactor-water purity to limit chemical and corrosive action, thereby limiting fouling and deposition on heat transfer surfaces. The RWCU System also removes corrosion products to limit impurities available for activation by neutron flux and resultant radiation from deposition of corrosion products. The system also provides a means for removal of reactor water.

The RWCU System provides continuous purification of a portion of the recirculation flow. The processed fluid is returned to the reactor vessel via the Feedwater System through the RCIC System and the HPCI System (Unit 3 only), to the Radwaste System, or to the main condenser. Regenerative heat exchangers are provided to limit heat loss from the nuclear system. The system can be placed in service at any time during normal reactor operation or shutdown conditions.

The major equipment of the RWCU System is located in the Reactor Building and consists of two pumps, regenerative and non-regenerative heat exchangers, and two filter/demineralizers with supporting equipment. The entire system is connected by associated valves and piping, and controls and instrumentation are provided for proper system operation. The RWCU System automatically isolates upon accident initiation and upon SLC System actuation.

The RWCU System is described in FSAR Section 4.9. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide reactor coolant pressure boundary. The RWCU System includes piping and valves that are part of the reactor coolant pressure boundary. 10 CFR 54.4(a)(1)
2. Provide primary containment boundary. The RWCU System includes piping and valves that are part of the primary containment boundary. 10 CFR 54.4(a)(1)
3. Provide system pressure boundary to support accomplishment of a safety-related function. The RWCU System includes a return isolation check valve to interconnections with the HPCI System to prevent diversion of HPCI flow from the reactor vessel. (Unit 3 only) 10 CFR 54.4(a)(1)
4. Resist spatial interaction of nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The RWCU System includes nonsafety-related fluid filled lines in the Reactor Building which have the potential for spatial interaction with safety-related SSCs in the Reactor Building. 10 CFR 54.4(a)(2)
5. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. The RWCU System includes nonsafety-related components that maintain structural integrity of the safety-related portions of the system. 10 CFR 54.4(a)(2)
6. Directly supports a safety-related function. The RWCU system includes nonsafety-related piping and valves in the blowdown/drain to radwaste that are relied upon to preserve the structural integrity of the Secondary Containment boundary. 10CFR 54.4(a)(2)
7. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). The RWCU System provides a portion of the reactor coolant pressure boundary. 10 CFR 54.4(a)(3)
8. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). The RWCU System includes valves that are required to isolate upon SLC System initiation in order to prevent removing sodium pentaborate in the RWCU demineralizers. 10 CFR 54.4(a)(3)
9. Portions of this system are relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). This system includes environmentally qualified electrical components. 10 CFR 54.4(a)(3)
10. Relied upon 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). 10 CFR 54.4(a)(3)
    - Reactor vessel isolation is required to meet NSPC Inventory Control Performance Criteria. The RWCU System must isolate for NSPC to succeed.

- Provide reactor coolant pressure boundary. The RWCU System includes piping and valves that are part of the reactor coolant pressure boundary.

FSAR References

Section 3.8

Sections 4.1, 4.9

Sections 5.2.3, 5.3

Section 7.3

Subsequent License Renewal Boundary Drawings

1-47E810-1-SLR

2-47E810-1-SLR

3-47E810-1-SLR

1-47E837-1-SLR

2-47E837-1-SLR

3-47E837-1-SLR

3-47E852-1-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-22, Reactor Water Cleanup System.

Table 2.3.3-22, Reactor Water Cleanup System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
Class 1 Piping, Fittings and Branch Connections < NPS 4	Pressure Boundary
Class 1 Valve Bodies and Bonnets	Pressure Boundary
Heat Exchangers	Pressure Boundary, Heat Transfer
Insulated Piping, Piping Components, Tanks	Pressure Boundary
Piping, Piping Components	Pressure Boundary
Tanks	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-22, Reactor Water Cleanup System - Summary of Aging Management Evaluation.

2.3.3.23 Reactor Building Closed Cooling Water System

Description

The Reactor Building Closed Cooling Water System provides a continuous supply of cooling water during normal operation to designated plant equipment located in the primary and secondary containment. A separate Reactor Building Closed Cooling Water System is provided for each unit. However, a single spare pump and heat exchanger located in Unit 1 may also be used by Unit 2 or Unit 3 through unit crosstie piping. The major components of each unit's Reactor Building Closed Cooling Water System are located in its respective reactor building and consist of two pumps and two heat exchangers cooled by the RCW System. The system is a closed system. Water cooled in the heat exchangers provides cooling water for components such as the Reactor Recirculation System pumps and motor, the RWCU System pumps and the non-regenerative heat exchanger, the fuel pool cooling heat exchanger, the drywell atmosphere cooling coils, the reactor building equipment drain sump heat exchanger, the drywell equipment drain sump heat exchanger, the drywell air compressors and aftercoolers, and sample coolers in the Sampling and Water Quality System. The system is normally operating. It automatically trips on accident initiation, but may be restarted manually, if desired.

The Reactor Building Closed Cooling Water System is described in FSAR Section 10.6. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide primary containment boundary. The Reactor Building Closed Cooling Water System includes piping and valves that are part of the primary containment boundary. 10 CFR 54.4(a)(1)
2. Provide secondary containment boundary. The Reactor Building Closed Cooling Water System includes piping and valves that are part of the secondary containment boundary. 10 CFR 54.4(a)(1)
3. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Reactor Building Closed Cooling Water System includes nonsafety-related fluid filled components which have the potential for spatial interaction with safety-related components. 10 CFR 54.4(a)(2)
4. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. The Reactor Building Closed Cooling Water System includes nonsafety-related piping that is relied upon to preserve the structural integrity safety-related RBCCW piping. 10 CFR 54.4(a)(2)
5. Directly support of a safety-related function. The Reactor Building Closed Cooling Water System includes nonsafety-related piping that is relied upon to preserve the Secondary Containment safety-related function. 10 CFR 54.4(a)(2)
6. Portions of this system are relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). This system includes environmentally qualified electrical components. 10 CFR 54.4(a)(3)
7. Relied upon 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). 10 CFR 54.4(a)(3)
    - The Reactor Building Closed Cooling Water System is included in the NFPA 805 analyses for multiple spurious operation and in the event of a real or spurious accident signal during a fire event, components within this system are designed and required to load shed in order to meet the NSPC Vital Auxiliaries Performance Criteria.

FSAR References

Section 5.2

Section 10.6

Appendix F.6.19

Subsequent License Renewal Boundary Drawings

1-47E822-1-SLR

2-47E822-1-SLR

3-47E822-1-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-23, Reactor Building Closed Cooling Water System.

Table 2.3.3-23, Reactor Building Closed Cooling Water System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
External Surfaces	Pressure Boundary
Heat Exchangers	Pressure Boundary, Heat Transfer
Insulated Piping, Piping Components, Tanks	Pressure Boundary
Piping, Piping Components	Pressure Boundary
Tanks	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-23, Reactor Building Closed Cooling Water System - Summary of Aging Management Evaluation.

2.3.3.24 Auxiliary Decay Heat Removal System

Description

The Auxiliary Decay Heat Removal (ADHR) System can be used to remove residual heat from the spent fuel pool and reactor cavity during outages. The ADHR System supplements the Fuel Pool Cooling and Cleanup System.

The ADHR System consists of two cooling water loops. The primary cooling loop circulates spent fuel pool water entirely inside the Reactor Building and rejects heat from the spent fuel pool to a secondary loop by means of a heat exchanger. The secondary loop transfers heat to the atmosphere outside the Reactor Building by means of evaporative cooling towers. The ADHR System includes piping and valves that are part of the secondary containment boundary.

The ADHR System is described in FSAR Section 10.22. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide secondary containment boundary. The ADHR System includes piping and valves that are part of the secondary containment boundary 10 CFR 54.4(a)(1)
2. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The ADHR System includes nonsafety-related fluid filled components which have the potential for spatial interaction with safety-related components. 10 CFR 54.4(a)(2)
3. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. The ADHR System includes nonsafety-related piping that is relied upon to preserve the structural integrity safety-related ADHR components located at the Secondary Containment boundary. 10 CFR 54.4(a)(2)

FSAR References

Section 10.22

Subsequent License Renewal Boundary Drawings

0-47E873-1-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-24, Auxiliary Decay Heat Removal System.

Table 2.3.3-24, Auxiliary Decay Heat Removal System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
Heat Exchangers	Pressure Boundary, Heat Transfer
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-24, Auxiliary Decay Heat Removal System - Summary of Aging Management Evaluation.

2.3.3.25 Containment Inerting System

Description

Following each startup (within 24-hours after thermal power is greater than 15% rated thermal power), the primary containment is purged of air with pure nitrogen until the atmosphere contains less than 4 percent oxygen. The Containment Inerting System is used during the initial purging of the primary containment and provides a supply of makeup nitrogen. The system consists of two liquid nitrogen storage tanks with two makeup vaporizers, a common purge vaporizer, pressure reducing valves and controllers, instrumentation valves and piping.

Nitrogen is supplied from the common onsite storage tanks through the common purge vaporizer or makeup vaporizers where the liquid nitrogen is converted to the gaseous state. The gaseous nitrogen then flows through the purge or makeup pressure-reducing valves and flow meters into each containment pressure suppression chamber or drywell, where it mixes with the air. A safety valve in the nitrogen supply system prevents over pressurization of the containment.

The primary containment atmosphere is monitored for oxygen and hydrogen by two redundant combustible gas analyzer subsystems. Each subsystem monitors torus and drywell oxygen and hydrogen for both the CAD System and Containment Inerting System. The CAD System is evaluated separately.

The Containment Inerting System is described in FSAR Sections 5.2.3.8 and 5.2.4.9. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide primary containment boundary. The Containment Inerting System includes piping and valves that are part of the primary containment boundary. 10 CFR 54.4(a)(1)
2. Control combustible gas mixtures within the primary containment atmosphere. The Containment Inerting System includes instrumentation that monitors hydrogen and oxygen levels in primary containment during accident conditions in support of CAD System operation. 10 CFR 54.4(a)(1)
3. Directly support a safety-related function. The Containment Inerting system includes nonsafety-related piping and valves from the nitrogen tank that are relied upon to preserve the structural integrity of the Secondary Containment boundary. 10 CFR 54.4(a)(2)
4. Portions of this system are relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). This system includes environmentally qualified electrical components. 10 CFR 54.4(a)(3)
5. Relied upon 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). 10 CFR 54.4(a)(3)
    - The Containment Inerting System supplies nitrogen to support MSRV operation to meet the NSPC Reactor Pressure Control Performance Criteria.
    - The Containment Inerting System supplies nitrogen to support MSRV operation to support the NSPC Reactor Inventory Control Performance Criteria.
    - The Containment Inerting System supplies nitrogen to support MSRV operation to support the NSPC Reactor Decay Heat Removal Performance Criteria.
    - The Containment Inerting System supplies nitrogen to support MSRV operation to meet the NSPC Vital Auxiliaries Performance Criteria.
    - Control combustible gas mixtures within the primary containment atmosphere. The Containment Inerting System includes instrumentation that monitors hydrogen and oxygen levels in primary containment during accident conditions in support of CAD System operation.

FSAR References

Sections 5.2.3.8, 5.2.4.9

Subsequent License Renewal Boundary Drawings

0-47E860-1-SLR

0-47E866-1-SLR

1-47E610-76-4-SLR

1-47E860-1-SLR

2-47E860-1-SLR

2-47E610-76-4-SLR

3-47E860-1-SLR

3-47E610-76-4-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-25, Containment Inerting System.

Table 2.3.3-25, Containment Inerting System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
External Surfaces	Pressure Boundary
Heat Exchangers	Pressure Boundary
Insulated Piping, Piping Components, Tanks	Pressure Boundary
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-25, Containment Inerting System - Summary of Aging Management Evaluation.

2.3.3.26 Radwaste System

Description

The Radwaste Systems are plant-shared systems that are designed to process the liquid and solid radioactive wastes generated during plant operation.

The Liquid Radwaste System collects, treats, and returns processed radioactive liquid wastes to the plant for reuse. Treated radioactive wastes not suitable for reuse are discharged from the plant through the condenser circulating water discharge system or are solidified and processed as solid radwaste. The collection system consists of sumps, tanks, piping and pumps for equipment and floor drains located in various areas of the plant including the primary and secondary containments. Treatment systems are located in the radwaste building.

The Solid Radwaste System collects, processes, stores, packages, and prepares solid radioactive waste materials for transfer to approved onsite storage areas or shipment to offsite processing or disposal facilities. Processing equipment is located in the radwaste building.

Gaseous radioactive waste is processed through the Ventilation Systems, the Standby Gas Treatment System, and the Off-Gas System.

The Low Level Radwaste Storage Facility is a series of modules for long-term storage of radioactive waste. Each module contains a sump with a through wall stainless steel pipe that is valved and blind flanged. This allows for sampling of potential drainage from materials. These mechanical components of the Low Level Radwaste Storage Facility are screened and evaluated as part of the Radwaste System.

The Radwaste System is described in FSAR Sections 4.10, 5.3, 9.1, 9.2, 9.3,10.16 and 12.2.5 and Appendix F.6.7, F.6.8, F.6.20, F.7.14. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide primary containment boundary. The Radwaste System includes piping and valves that are part of the primary containment boundary. 10 CFR 54.4(a)(1)
2. Provide pressure boundary integrity. The Radwaste System includes piping and components connecting to the safety-related Standby Gas Treatment System and safety-related portion of the Off-Gas System that are required to maintain their pressure boundary integrity so as not to jeopardize the ability of the Standby Gas Treatment and Off-Gas Systems to perform their nuclear safety functions. 10 CFR 54.4(a)(1)
3. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Radwaste System includes nonsafety-related fluid filled lines which have the potential for spatial interaction with safety-related components. 10 CFR 54.4(a)(2)
4. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. The Radwaste System includes nonsafety-related piping that is relied upon to preserve the structural integrity of safety-related Radwaste piping. 10 CFR 54.4(a)(2)
5. Directly support a safety-related function. The Radwaste System includes nonsafety-related piping that is relied upon to preserve the Secondary Containment safety-related function. 10 CFR 54.4(a)(2)
6. Portions of this system are relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). This system includes environmentally qualified electrical components. 10 CFR 54.4(a)(3)
7. Relied upon 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). 10 CFR 54.4(a)(3)
   - NSPC Radioactive Release Performance Criteria: The Radwaste System contains effluent from the fire and fire suppression activities.
   - NSPC Vital Auxiliaries Performance Criteria: The Radwaste system is included in the NFPA 805 analyses for load shed considerations, in order to demonstrate the NSPC Vital Auxiliaries Performance Criteria is met.
   - NSPC Inventory Control Performance Criteria: The Radwaste system is included in the NFPA 805 analyses for multiple spurious operations considerations. Multiple spurious

operation could create a drain path from the reactor vessel, or divert makeup water sources away from the reactor vessel. Multiple spurious operation could also affect containment overpressure and ECCS pumps net positive suction head impacting inventory control.

- NSPC Decay Heat Removal Performance Criteria: Multiple spurious operation could also affect containment overpressure and RHR pumps net positive suction head impacting decay heat removal.

<u>FSAR References</u>

Section 4.10

Section 5.3

Sections 9.1, 9.2, 9.3

Section 10.16

Section 12.2.5

Appendix F.6.7, F.6.8, F.6.20, F.7.14

<u>Subsequent License Renewal Boundary Drawings</u>

0-47E830-1-SLR

0-47E830-2-SLR

0-47E830-3-SLR

0-47E830-5-SLR

0-47E830-6-SLR

0-47E830-9-SLR

0-47E832-1-SLR

0-47E835-1-SLR

1-47E831-3-SLR

1-47E851-2-SLR

1-47E852-1-SLR

1-47E852-2-SLR

2-47E851-2-SLR

2-47E852-1-SLR

2-47E852-2-SLR

2-47E850-6-SLR

3-47E851-2-SLR

3-47E852-1-SLR

3-47E852-2-SLR

<u>Components Subject to AMR</u>

The component types that require aging management review are indicated in the below Table 2.3.3-26, Radwaste System.

Table 2.3.3-26, Radwaste System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
Heat Exchangers	Pressure Boundary, Heat Transfer
Insulated Piping, Piping Components, Tanks	Pressure Boundary
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-26, Radwaste System - Summary of Aging Management Evaluation.

2.3.3.27 Spent Fuel Pool Cooling/Cleanup System

Description

The Spent Fuel Pool Cooling/Cleanup System removes residual heat from the fuel assemblies and maintains the fuel pool water within specified temperature limits. It minimizes corrosion product buildup, controls water clarity in the fuel pool water so that the fuel assemblies can be efficiently handled underwater and minimizes fission product concentration in the fuel pool water.

The Spent Fuel Pool Cooling/Cleanup System for each unit has two pumps that circulate the fuel pool water through a heat exchanger and a filter demineralizer. Each unit has two heat exchangers cooled by the Reactor Building Closed Cooling Water System. The Spent Fuel Pool Cooling/Cleanup System has a cross-connection with the RHR System by which the RHR System can provide supplemental cooling. The pumps and heat exchangers are located in the Reactor Building. Four filter demineralizers are located in the Radwaste Building. One filter demineralizer is a spare that may be used by any unit. Provisions are made for secondary containment integrity. The system is normally operating. Provisions are made to prevent siphoning the fuel pool, check valves in each of the fuel pool cleanup return diffuser lines are provided with a siphon breaking vent pipe in order to prevent siphoning of fuel pool water to no more than 6 inches below the normal water level.

The Spent Fuel Cooling/Cleanup System is described in FSAR Section 10.5. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide pressure boundary integrity. The Spent Fuel Pool Cooling/Cleanup System includes piping and components at the RHR System interfaces that are required to maintain their pressure boundary integrity so as not to jeopardize the ability of the RHR System to perform its nuclear safety functions. 10 CFR 54.4(a)(1)
2. Prevent inadvertent siphoning of the spent fuel pool. Check valves in each of the fuel pool cleanup return diffuser lines are provided with a siphon breaking vent pipe in order to prevent siphoning of fuel pool water to no more than 6 inches below the normal water level.
   10 CFR 54.4(a)(1)

3. Resist spatial interaction of nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Spent Fuel Pool Cooling/Cleanup System includes nonsafety-related fluid filled lines in the Reactor Building which have the potential for spatial interaction with safety-related SSCs in the Reactor Building. 10 CFR 54.4(a)(2)
4. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. The Spent Fuel Pool Cooling/Cleanup System includes nonsafety-related components that maintain structural integrity of safety-related components in RHR system and secondary containment structures. 10 CFR 54.4(a)(2)
5. Directly support a safety-related function. The Spent Fuel Pool Cooling/Cleanup system includes nonsafety-related piping and valves in the drain to main condenser that are relied upon to preserve the structural integrity of the Secondary Containment boundary. 10 CFR 54.4(a)(2)
6. Relied upon 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). 10 CFR 54.4(a)(3)
    - The Spent Fuel Pool Cooling and Cleanup System is included in the NFPA 805 analyses for multiple spurious operation and in the event of a real or spurious accident signal during a fire event, components within this system are designed and required to load shed in order to meet the NSPC Vital Auxiliaries Performance Criteria.

FSAR References

Section 4.8

Sections 10.5, 10.22

Subsequent License Renewal Boundary Drawings

0-47E830-6-SLR

0-47E832-1-SLR

1-47E832-1-SLR

1-47E855-1-SLR

2-47E832-1-SLR

2-47E855-1-SLR

3-47E832-1-SLR

3-47E855-1-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-27, Spent Fuel Pool Cooling/Cleanup System.

Table 2.3.3-27, Spent Fuel Pool Cooling/Cleanup System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
Heat Exchangers	Pressure Boundary, Heat Transfer

Table 2.3.3-27, Spent Fuel Pool Cooling/Cleanup System (Continued)

Component Type	Passive Intended Functions
Insulated Piping And Piping Components, Tanks	Pressure Boundary
Piping, Piping Components	Pressure Boundary
Tanks	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-27, Spent Fuel Pool Cooling/Cleanup System - Summary of Aging Management Evaluation.

2.3.3.28 Fuel Handling and Storage System

Description

Each unit is provided with a dry new fuel storage vault. The new fuel storage racks provide a storage place in the new fuel storage vaults for new fuel. However, new fuel is not placed in the new fuel storage racks until a criticality analysis of optimum moderator configuration is performed. In accordance with BFN Technical Specification 4.3.1.2, “The new fuel storage vault shall not be used for fuel storage. New fuel shall be stored in the spent fuel storage racks.”

There are three spent fuel storage pools, one per reactor. A transfer canal is provided to join the Unit 1 and the Unit 2 pools. The spent fuel storage racks provide a storage place at the bottom of each fuel pool for the spent fuel received from the reactor vessel. The racks are full length, top entry, and are designed to maintain the spent fuel in a spatial geometry that precludes the possibility of criticality. The racks are made of staggered, stainless-steel container tubes. Each tube wall has a core of Boral sandwiched within stainless steel.

Servicing equipment is provided to facilitate refueling, fuel inspection and fuel maintenance.

The Fuel Handling and Storage System is described in FSAR Sections 10.2, 10.3, 10.4, and 10.5. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Maintain structural integrity. The fuel storage pool of the Fuel Handling and Storage System shall maintain structural integrity to ensure that a minimum required water level is maintained in the pool. 10 CFR 54.4(a)(1)
2. Provide criticality protection. The fuel storage racks of the Fuel Handling and Storage System shall maintain stored new and spent fuel subcritical by a substantial margin by utilizing storage racks with integral Boral neutron absorption sheets and physical spacing. 10 CFR 54.4(a)(1)
3. Resist spatial interaction of nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Fuel Handling and Storage System includes nonsafety-related heavy equipment such as cranes and hoists in the Reactor Building/Refuel Floor that have the potential for spatial interactions with safety-related SSCs.
   10 CFR 54.4(a)(2)
4. Provides a safe means for handling safety-related components and loads above or near safety-related components. The Fuel Handling and Storage System components within the

scope of license renewal handle equipment and fuel above or near safety-related components or irradiated fuel. 10 CFR 54.4(a)(2)

FSAR References

Sections 10.2, 10.3, 10.4, 10.5

Appendix F.7.3

Subsequent License Renewal Boundary Drawings

1-47E855-1-SLR

2-47E855-1-SLR

3-47E855-1-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-28, Fuel Handling and Storage System.

Table 2.3.3-28, Fuel Handling and Storage System

Component Type	Passive Intended Functions
Cranes: Rails, Bridges, Structural Members, Structural Components	Structural Support
Cranes: Structural Bolting	Structural Support
Spent Fuel Storage Racks: Neutron-absorbing Sheets (BWR)	Absorbs Neutrons
Spent Fuel Storage Racks (BWR)	Structural Support

The aging management review results for these components are provided in Table 3.3.2-28, Fuel Handling and Storage System - Summary of Aging Management Evaluation.

2.3.3.29 Standby Diesel Generators

Description

The Standby Diesel Generator System provides an alternate source of power to the ECCS and the safe shutdown systems when the normal power supplies are not available. Each Diesel Generator unit consists of a diesel engine, a generator, and auxiliary systems (starting air, fuel oil, jacket cooling, engine exhaust and combustion air, and lubricating oil). Diesel Generator Starting Air and Fuel Oil, are each evaluated separately.

The Standby Diesel Generator System is a plant-shared system. The Standby Diesel Generator System consists of four independent Diesel Generator units coupled as an alternate independent source of power to four 4160-V shared shutdown boards for Units 1 and 2. There are four additional Diesel Generator units that provide an alternate independent source of power to four Unit 3 4160-V shutdown boards. Breaker ties allow a Unit 1 and Unit 2 Diesel Generators to feed a Unit 3 shutdown board. The same breaker ties allow a Unit 3 Diesel Generator to feed a Unit 1 and Unit 2 shutdown board. The Diesel Generators are normally in standby and start automatically when required. Each Diesel Generator is automatically started on loss of offsite power, low reactor water level, or high drywell pressure signals coincident with low reactor pressure. The Diesel Generators are located in the Diesel Generator Buildings.

Most of the Standby Diesel Generators system is safety-related but it includes nonsafety-related oil filled lines in the Diesel Generator Building that have the potential for spatial interactions with safety-related SSCs.

The Standby Diesel Generator System is described in FSAR Section 8.5. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide motive power to safety-related components. The Standby Diesel Generator System is required to power safety-related equipment in the event normal offsite power sources are not available. 10 CFR 54.4(a)(1)
2. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. Nonsafety-related Standby Diesel Generator System piping is relied upon to maintain structural integrity of safety-related Standby Diesel Generator System components. 10 CFR 54.4(a)(2)
3. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Standby Diesel Generator System includes nonsafety-related fluid filled lines in the Diesel Generator Building which have the potential for spatial interaction with safety-related SSCs. 10 CFR 54.4(a)(2)
4. Portions of this system are relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). This system includes environmentally qualified electrical components. 10 CFR 54.4(a)(3)
5. Relied upon 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). 10 CFR 54.4(a)(3)
    - The Standby Diesel Generator System is a support system for the NSPC Vital Auxiliaries Performance Criteria. Provide motive power to safety-related components. The Standby Diesel Generator System is required to power safety-related equipment in the event normal offsite power sources are not available.
6. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Standby Diesel Generators in the non-blacked-out units are credited with providing power to common equipment supporting the blacked-out unit and as a source of power restoration using existing cross-ties.

FSAR References

Sections 7.4, 7.18

Sections 8.4, 8.5, 8.10

Appendix F.7.9

Subsequent License Renewal Boundary Drawings

0-47E840-3-SLR
0-47E861-5-SLR
0-47E861-6-SLR
0-47E861-7-SLR
0-47E861-8-SLR
0-55E715-2-SLR
3-47E861-5-SLR
3-47E861-6-SLR
3-47E861-7-SLR
3-47E861-8-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-29, Standby Diesel Generators.

Table 2.3.3-29, Standby Diesel Generators

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
External Surfaces	Pressure Boundary
Heat Exchangers	Pressure Boundary, Heat Transfer
Insulated Piping, Piping Components, Tanks	Pressure Boundary
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-29, Standby Diesel Generators - Summary of Aging Management Evaluation.

2.3.3.30 Supplemental Diesel Generator System

Description

The Supplemental Diesel Generator (SDG) System provides a non-safety related highly reliable backup source of power for the Emergency High Pressure Makeup (EHPM) System and auxiliaries. The SDG System is manually started and aligned to provide an alternate source of power for the EHPM system and auxiliaries during fire events where the normal power supply to the EHPM system has failed. Each SDG is capable of supplying the EHPM system loads for all three units.

The SDG System consists of two 4160 V, 3250 kW air-cooled Diesel Generators and associated equipment in an enclosure located in the yard. All support equipment required to maintain standby readiness and normal utility loads are normally powered by an external utility power feed and are automatically transferred to the SDGs in emergency conditions. Power required to start the SDGs and energize the SDG distribution system is supplied by SDG mounted batteries. This allows the SDG system to be placed in emergency service without dependence on external support systems. Additionally, an external 480 V connection is provided for connection of a temporary external power source to the Supplemental DG distribution system.

The SDG System is described in FSAR Section 10.24. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Relied upon 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).
   10 CFR 54.4(a)(3)
   - The SDG system is included in the fire protection analysis to improve risk margin for core damage frequency and large and early release frequency in support of the NSPC Inventory Control Performance Criteria

FSAR References

Section 10.24

Subsequent License Renewal Boundary Drawings

0-47E610-83-1-SLR

0-47E610-83-2-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-30, Supplemental Diesel Generator System.

Table 2.3.3-30, Supplemental Diesel Generator System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
External Surfaces	Pressure Boundary
Heat Exchangers	Pressure Boundary, Heat Transfer
Insulated Piping, Piping Components, Tanks	Pressure Boundary
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-30, Supplemental Diesel Generator System - Summary of Aging Management Evaluation.

2.3.3.31 Control Rod Drive System

Description

The CRD System is a reactivity control system that utilizes pressurized demineralized water to rapidly insert control rods to shutdown the reactor upon receipt of a scram signal from the Reactor Protection System. The CRD mechanisms are part of the CRD System. The CRD System hydraulically operates the CRD mechanisms using water from the condensate storage system as a hydraulic fluid. The CRD System also provides for manual control of core reactivity and power generation by incrementally positioning neutron-absorbing control rods in response to signals from the Reactor Manual Control System. The CRD System includes the ARI System, which provides an alternate means of venting the scram air header and inserting control rods that is independent of the Reactor Protection System. The ARI function serves to reduce the probability of an ATWS event and may be initiated automatically or manually.

The CRD System provides reactivity control by allowing positioning of the control rods at a controlled rate during normal operation, providing scram and diverse scram (ARI) functions to ensure a rapid shutdown when required. It also limits rod drop rate to minimize the consequences of a rod drop accident, and limits a rod ejection accident.

Each unit has separate hydraulic CRDs and hydraulic control units that control flow from the CRD hydraulic subsystem that enables the system to rapidly and fully insert all control rods when a scram is required. CRD provides normal drive flow to re-position individual control rods at slow speed when required and is used for control rod positioning during normal plant operations. It also provides cooling water flow that continually ensures required cooling of all CRDs without control rod motion.

A scram discharge volume receives the water displaced from the drives during a scram and maintains the reactor coolant pressure boundary and primary containment integrity. Control rod drop speed is limited by an integral velocity limiter and a control rod ejection is limited by the CRD housing support. The CRD hydraulic subsystem is a plant-shared system. Each unit has its dedicated pump that takes suction from the Condensate Transfer System. There is a spare pump shared between Unit 1 and Unit 2. Unit 3 has a dedicated spare pump. The CRD System has safety-related components that are relied upon to preserve structural integrity of primary containment and reactor coolant pressure boundaries. The CRD System also includes nonsafety-related water filled lines in the Reactor Building that have the potential for spatial and structural interactions with safety-related SSCs. Additionally, the CRD System directly supports a safety-related function, because nonsafety components are relied upon to preserve the structural integrity of the Secondary Containment boundary.

The CRD System is described in FSAR Sections 3.4 and 3.5. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide primary containment boundary. The CRD System includes piping and valves that are part of the primary containment boundary. 10 CFR 54.4(a)(1)
2. Provide reactor coolant pressure boundary. The CRD System includes piping and valves that are part of the reactor coolant pressure boundary. 10 CFR 54.4(a)(1)
3. Introduce negative reactivity to achieve or maintain subcritical reactor condition. The CRD System hydraulic control units provide the motive force to the control rod drive mechanisms to rapidly insert control rods during a scram event to prevent or limit fuel damage following abnormal transients and design bases accidents. 10 CFR 54.4(a)(1)
4. Resist spatial interaction of nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The CRD System includes nonsafety-related fluid filled lines in the Reactor Building which have the potential for spatial interaction with safety-related SSCs in the Reactor Building. 10 CFR 54.4(a)(2)

5. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. The CRD System includes nonsafety-related components that maintain structural integrity of the safety-related portions of the system. 10 CFR 54.4(a)(2)
6. Directly support a safety-related function. The CRD System includes nonsafety-related piping and valves in the drain to main condenser that are relied upon to preserve the structural integrity of the Secondary Containment boundary. 10 CFR 54.4(a)(2)
7. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). The CRD System provides a portion of the reactor coolant pressure boundary. 10 CFR 54.4(a)(3)
8. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). The CRD System includes the ARI System that provides an alternate means of venting the scram air header and inserting control rods that is independent of the Reactor Protection System. 10 CFR 54.4(a)(3)
9. Portions of this system are relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). This system includes environmentally qualified electrical components. 10 CFR 54.4(a)(3)
10. Relied upon 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). 10 CFR 54.4(a)(3)
    - Provide reactor coolant pressure boundary. The CRD System includes piping and valves that are part of the reactor coolant pressure boundary.
    - Introduce negative reactivity to achieve or maintain subcritical reactor condition. The CRD System hydraulic control units provide the motive force to the control rod drive mechanisms to rapidly insert control rods during a scram event to prevent or limit fuel damage following abnormal transients and design bases accidents.

<u>FSAR References</u>

Sections 3.4, 3.5, 3.7

Section 5.2.3

Sections 7.7, 7.19

Appendix F.7.12

Appendix N

<u>Subsequent License Renewal Boundary Drawings</u>

0-47E820-1-SLR

1-47E820-2-SLR

1-47E820-6-SLR

1-47E820-7-SLR

2-47E820-2-SLR

2-47E2820-6-SLR

2-47E820-7-SLR

3-47E820-2-SLR
3-47E820-6-SLR
1-47E844-2-SLR
2-47E844-2-SLR
3-47E844-2-SLR
3-47E820-6-SLR
3-47E820-7-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-31, Control Rod Drive System.

Table 2.3.3-31, Control Rod Drive System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
External Surfaces	Pressure Boundary
Heat Exchangers	Pressure Boundary, Heat Transfer
Insulated Piping, Piping Components	Pressure Boundary
Piping, Piping Components	Pressure Boundary
Tanks	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-31, Control Rod Drive System - Summary of Aging Management Evaluation.

2.3.3.32 Diesel Generator Starting Air System

Description

The Diesel Generator Starting Air System consists of piping, valves, air dryers, air receiver tanks, air motors, filters and associated equipment that assist the Standby Diesel Generator System to start the diesel engines and provide an alternate source of power.

Each Diesel Generator has its own independent Starting Air System. The Diesel Generator Starting Air System for each Diesel Generator consists of two independent subsystems, either one of which can start the Diesel Generator. Each subsystem consists of an air compressor with associated filters and coolers and a bank of air receivers. The air compressors operate automatically to maintain the receivers pressurized. The Diesel Generator Starting Air System is located in the Diesel Generator Buildings.

The Diesel Generator Starting Air System is described in FSAR Section 8.5.3.3. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Support the Diesel Generators in performing their nuclear safety function. The Diesel Generator Starting Air System provides Diesel Generator starting air to support the Diesel Generators providing motive power to safety-related components in the event normal offsite power sources are not available. 10 CFR 54.4(a)(1)
2. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. The Diesel Generator Starting Air System includes nonsafety-related components that maintain structural integrity of the safety-related portions of the system. 10 CFR 54.4(a)(2)
3. Directly supports a safety-related function. The Diesel Generator Starting Air System includes nonsafety-related piping and valves in the drain to main condenser that are relied upon to preserve the structural integrity of the Secondary Containment boundary. 10 CFR 54.4(a)(2)
4. Relied upon 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). 10 CFR 54.4(a)(3)
   - The Standby Diesel Generator System is a support system for the NSPC Vital Auxiliaries Performance Criteria. Provide motive power to safety-related components. The Standby Diesel Generator System is required to power safety-related equipment in the event normal offsite power sources are not available.
5. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Diesel Generator Starting Air System provides Diesel Generator starting air to support the Diesel Generators in the non-blacked-out units. 10 CFR 54.4(a)(3)

FSAR References

Section 8.5.3.3

Subsequent License Renewal Boundary Drawings

0-47E861-1-SLR
0-47E861-2-SLR
0-47E861-3-SLR
0-47E861-4-SLR
0-47E861-5-SLR
0-47E861-6-SLR
0-47E861-7-SLR
0-47E861-8-SLR
3-47E861-1-SLR
3-47E861-2-SLR
3-47E861-3-SLR
3-47E861-4-SLR
3-47E861-5-SLR
3-47E861-6-SLR
3-47E861-7-SLR
3-47E861-8-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-32, Diesel Generator Starting Air System.

Table 2.3.3-32, Diesel Generator Starting Air System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
Insulated Piping, Piping Components, Tanks	Pressure Boundary
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-32, Diesel Generator Starting Air System - Summary of Aging Management Evaluation.

2.3.3.33 Cranes and Hoists

Description

The Cranes and Hoists System has individual cranes and hoists in each unit, as well as the Reactor Building (overhead) Crane, shared between units. Cranes and hoists are essentially self-contained and primarily mechanical components, although in most cases, cranes and hoists are electrically powered, and operated by electric motors and controls. Cranes and hoists are nonsafety-related.

The Reactor Building crane is a single-trolley, overhead electric traveling-type with a 125-ton main hoist, a 5-ton auxiliary hoist, and a span of 106 ft 5 in. All motions are driven by AC motors. Single-failure protection is provided for all crane components except the hoist wire rope drum shell, trolley cross girts and bridge girders. The one crane is used for three reactor units. It handles the spent fuel casks, dry storage casks and equipment, equipment for the service and maintenance of the reactors, and equipment which is received or shipped through the equipment access lock.

Each unit Turbine Building is provided with an overhead, electric, single-trolley, traveling crane. The main hoist of the Unit 3 Turbine Building crane is rated at 180 tons and the auxiliary hoists at 25 tons. The Units 1 and 2 main hoist are rated at 210 tons and the auxiliary hoist at 25 tons. The cranes are designed as Class II equipment.

Overhead-handling systems located in structures that contain safety-related SSCs are designed to meet seismic II/I criteria if, by nature of their location, they would have the potential to drop a load resulting in damage to a structure or component that prevents the satisfactory accomplishment of a safety-related intended function. The Cranes and Hoists System includes cranes, monorails, hoists, and mobile A-frames.

Cranes and Hoists are described in FSAR Sections 10.4 and 12.2, Appendix C.8, and Appendix F.7.4.

Intended Functions

1. Resist spatial interaction of nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Cranes and Hoists System includes nonsafety-related cranes, monorails, hoists, and mobile A-frames in safety-related structures which have the potential for spatial interaction with safety-related systems and components. 10 CFR 54.4(a)(2)
2. Relied upon 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). 10 CFR 54.4(a)(3).
    - In the event of a real or spurious accident signal during a fire event, components within the Cranes and Hoists System are designed and required to load shed in order to meet the NSPC Vital Auxiliaries Performance Criteria.

FSAR Sections

Section 10.4

Section 12.2

Appendix C.8

Appendix F.7.4

Subsequent License Renewal Boundary Drawings

None

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-33, Cranes and Hoists.

Table 2.3.3-33, Cranes and Hoists

Component Type	Passive Intended Functions
Cranes; Structural Bolting	Structural Support
Cranes: Bridges, Structural Members, Structural Components	Structural Support
Cranes: Rails, Bridges, Structural Members, Structural Components	Structural Support

The aging management review results for these components are provided in Table 3.3.2-33, Cranes and Hoists - Summary of Aging Management Evaluation.

2.3.3.34 Sewage System

Description

The potable water for use in the plumbing systems is supplied by the city of Athens, Alabama. Backflow preventers have been installed at each cross connection to other systems to protect the potable water supply from possible contamination due to backflow. Sewage from the BFN site is collected and treated.

These shared systems do not influence the operational safety of the plant. The portions of the systems which penetrate secondary containment were evaluated to ensure they could prevent seismically induced failure from causing a breach of containment. The lines are provided with valves to ensure the containment integrity if the piping systems are damaged by seismically induced loads.

The Sewage System is described in FSAR Sections 10.15 and 11.6.

Intended Functions

1. Relied upon 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). 10 CFR 54.4(a)(3).
   - In the event of a real or spurious accident signal during a fire event, components within the Sewage System are designed and required to load shed in order to meet the NSPC Vital Auxiliaries Performance Criteria.

FSAR References

Section 10.15

Section 11.6

Subsequent License Renewal Boundary Drawings

None

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-34, Sewage System.

Table 2.3.3-34, Sewage System

Component Type	Passive Intended Functions
Load Shed Relay	Not Applicable

The aging management review results for these components are provided in Table 3.3.2-34, Sewage System - Summary of Aging Management Evaluation.

2.3.3.35 Diverse and Flexible Coping Strategies (FLEX) System

Description

The FLEX System is a collection of equipment and strategies implemented through procedures that provides extended coping capability for Beyond Design Basis External Events.

The FLEX System strategies are accomplished through the use of FLEX equipment which interfaces or connects with other plant systems and equipment. These connections are generally made through the use of non-FLEX system plant equipment, such as test connections used for the Drywell Control Air and CAD Systems, or by temporary connections to electrical distribution systems.

There are FLEX System components which provide a permanent interface to the RHRSW System and EECW Systems. The FLEX connection manifolds to RHRSW System headers B and D and the EECW System are located in the Intake Pumping Station rooms.

The FLEX System is described in FSAR Sections 5.2.6, 10.9, 10.10, and 10.14.4. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide pressure boundary integrity. The FLEX System includes piping and components at the RHRSW and EECW System interfaces that are required to maintain their pressure boundary integrity so as not to jeopardize the ability of the RHRSW and EECW Systems to perform their nuclear safety functions. 10 CFR 54.4(a)(1)
2. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. Nonsafety-related FLEX drain lines and valves are mechanically connected to the safety-related FLEX manifold isolation valves. 10 CFR 54.4(a)(2)
3. Resist spatial interaction of nonsafety-related FLEX equipment that could prevent satisfactory accomplishment of a safety-related function. The FLEX equipment includes nonsafety-related pumps, valves, and supports/restraints in safety-related structures which have the potential for spatial interaction with safety-related systems and components. 10 CFR 54.4(a)(2)

FSAR References

Section 5.2.6

Sections 10.9, 10.10, 10.14.4

Subsequent License Renewal Boundary Drawings

1-47E858-1-SLR

1-47E859-1-SLR

2-47E862-1-SLR

3-47E862-1-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-35, FLEX System.

Table 2.3.3-35, FLEX System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
External Surfaces	Pressure Boundary
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-35, FLEX System - Summary of Aging Management Evaluation.

2.3.3.36 Security System

Description

The Security System provides the physical security features of the plant. In addition to components related to physical security, the system provides card readers that support access/ egress during fire events and station blackout events. A diesel generator provides backup power for the system. The security system diesel generator consists of the diesel generator and associated fuel oil, lubricating oil, cooling water, intake, and exhaust support subsystems.

The Security System facilitates access to locations requiring credited operator recovery actions. Specifically, the security card reader and magnetic lock are required for entry through security doors. The card readers and magnetic locks are active components. As discussed in the associated calculation, the failure modes for these components continue to allow access through the door. The intended function of these components is met when power is lost.

Intended Functions

1. Relied upon 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). The Security System facilitates access to locations requiring credited operator recovery actions. 10 CFR 54.4(a)(3)
2. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout. (10 CFR 50.63) The Security System facilitates access to locations requiring credited operator recovery actions. 10 CFR 54.4(a)(3)

FSAR References

None

Subsequent License Renewal Boundary Drawings

None

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-36, Security System.

Table 2.3.3-36, Security System

Component Type	Passive Intended Functions
Card Reader	Not Applicable
Magnetic Lock	Not Applicable

The aging management review results for these components are provided in Table 3.3.2-36, Security System - Summary of Aging Management Evaluation.

2.3.3.37 Radiation Monitoring System

Description

The Radiation Monitoring System is a system which monitors various processes and areas for radioactivity levels. Portions of the Radiation Monitoring System are common to all three units. The Radiation Monitoring System consists of safety-related and nonsafety-related portions and is in scope for subsequent license renewal; however, nonsafety-related portions that are not required to perform subsequent license renewal intended functions are not in scope.

The safety-related radiation monitors included in the system are as follows:

- Reactor Building Ventilation Radiation
- Refuel Zone Ventilation Radiation
- Drywell Leak Detection Radiation
- Primary Containment Area High-Range Radiation
- Control Room Air Supply Duct Radiation

The nonsafety-related radiation monitors included in the system are as follows:

- Main Steam Line Radiation
- Air Ejector Off-gas Radiation
- Main Stack Radiation Monitoring
- Process Liquid Radiation (RHRSW discharge, RCW discharge, Liquid Radioactive Waste discharge, Reactor Building Closed Cooling Water
- Plant Ventilation Exhaust Radiation
- Air Particulate Radiation

The reactor building ventilation radiation monitors detect the radiation in the Reactor Building ventilation exhaust line prior to its discharge from the structure. If an abnormal condition is detected, an input is provided to initiate Standby Gas Treatment System, Primary Containment Isolation, Secondary Containment Isolation, and CREV System.

The refueling zone ventilation exhaust radiation monitors detect the radiation near the spent fuel pools on the refueling floor. If an abnormal condition is detected, an input is provided to initiate Standby Gas Treatment System, Primary Containment Isolation, Secondary Containment Isolation, and CREV System.

The drywell leak detection radiation monitors provide diverse primary coolant leak detection ability. In the event of abnormally high concentrations of radioactive particulates, iodines, and noble gases within the drywell due to primary coolant leakage, these monitors will initiate annunciation in the control room. To prevent the release of radioactive material to areas of the plant outside of the containment boundary, primary containment isolation signals are provided to initiate closure of containment isolation valves on the suction and return line to the drywell leak detection radiation monitors.

The primary containment area high-range radiation monitors detect and measure the radiation level within the drywell during and following an accident. These monitors provide information to the operators to help assess the extent of post-accident core damage.

The control room air supply duct radiation monitors detect radioactivity in the control bay ventilation supply line for the control rooms. The ventilation supply line is monitored to detect the amount of radioactive material entering the control rooms, to assure that personnel are not exposed to excessive doses. If an abnormal condition is detected, the control room air supply duct radiation monitors provide input to initiate filtration of the ventilation supply air through the CREV System.

The Main Stack Radiation Monitoring System indicates whenever limits on the release of radioactive noble gases to the environment are reached or exceeded, to obtain representative samples of radioactive iodine and particulates for laboratory analysis, and to indicate the rate of radioactive noble gas release during planned operations and during or following an accident. The Main Stack Radiation Monitoring System includes nonsafety-related piping components attached to safety-related ductwork associated with the Off-Gas System.

The RHRSW discharge radiation monitors detect the radiation level in the RHRSW System discharge. Changes in the normal radiation level in the RHRSW discharge could indicate leakage in the RHR heat exchangers. System pressure boundary integrity at the RHRSW discharge radiation monitors interface of the RHRSW discharge header is required to be maintained to prevent flooding of the Reactor Building.

The Process Liquid Radiation Monitoring System processes streams for RCW and RHRSW that normally discharge to the environment, and indicates when operational limits for the normal release of radioactive material to the environment are exceeded. These systems include nonsafety-related components that are connected to piping that penetrate the Reactor Building and are required to preserve the structural integrity of the secondary containment boundary.

The portions of the Radiation Monitoring System that are not in scope for subsequent license renewal include main steam line radiation monitoring, air ejector off-gas radiation monitoring, process liquid radiation monitoring (excluding RHRSW discharge radiation monitoring), plant ventilation exhaust radiation monitoring, and air particulate radiation monitoring.

The Radiation Monitoring System is described in FSAR Sections 5.2.3, 7.12, 7.13, 7.14, and Appendix F.7.5. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

<u>Intended Functions</u>

1. Provide primary containment boundary. The Radiation Monitoring System includes piping and valves that are part of the primary containment boundary. 10 CFR 54.4(a)(1)
2. Sense process conditions and generate signals for engineered safety features actuation. The Radiation Monitoring System monitors parameters for radiation level and initiates appropriate protective action to limit the potential release of radioactive materials if predetermined levels are exceeded. 10 CFR 54.4(a)(1)

3. Directly support a safety-related function. The Radiation Monitoring System includes nonsafety-related components that are relied on to preserve the structural integrity of the secondary containment boundary. 10 CFR 54.4(a)(2)
4. Resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The Radiation Monitoring System includes nonsafety-related piping components that have the potential for structural interaction with safety related SSCs that perform a 10 CFR 54.4(a)(1) function. 10 CFR 54.4(a)(2)
5. Resist spatial interaction of nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Radiation Monitoring System includes nonsafety-related liquid-filled piping components that have the potential for spatial interaction with safety-related RHRSW discharge piping. This includes the nonsafety-related portions of the system located within the Reactor Building. 10 CFR 54.4(a)(2)
6. Maintain system pressure boundary integrity. System pressure boundary integrity at the Radiation Monitoring System interface of the RHRSW discharge header is required to be maintained to prevent flooding. 10 CFR 54.4(a)(2)
7. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). The Radiation Monitoring System includes environmentally qualified electrical components. 10 CFR 54.4(a)(3)

FSAR References

Section 5.2.3

Sections 7.12, 7.13, and 7.14

Appendix F.7.5

Subsequent License Renewal Boundary Drawings

0-47E610-90-4-SLR

1-47E610-90-1-SLR

2-47E610-90-1-SLR

3-47E610-90-1-SLR

0-47E610-90-2-SLR

1-47E610-90-3-SLR

2-47E610-90-3-SLR

3-47E610-90-3-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-37, Radiation Monitoring System.

Table 2.3.3-37, Radiation Monitoring System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-37, Radiation Monitoring System - Summary of Aging Management Evaluation.

2.3.3.38 Hardened Containment Venting System

Description

The Hardened Containment Venting System provides a direct vent path from the torus (wetwell) to independent release points above the Reactor Building. There is one separate Hardened Containment Venting System for each unit. The vent flow path exits the torus via the pressure suppression chamber supply line. The vent pathway consists of a torus penetration, the pressure suppression chamber supply piping, primary containment isolation valves, and a line that exits the Reactor Building. The line that exits the Reactor Building transitions to the exterior in an underground valve pit before turning and routing vertically up the Reactor Building. At the elevation of the Reactor Building refuel floor area, the line re-enters the Reactor Building and then continues to the vent termination/release point above the Reactor Building roof. Two pneumatically operated butterfly valves provide primary containment isolation and can be remotely operated from the Main Control Room. During normal plant operation, the Hardened Containment Venting System primary containment isolation valves remain closed.

The Hardened Containment Venting System is credited in the Fire Probabilistic Risk Assessment (PRA) model for decay heat removal when all other decay heat removal functions are lost. The portion of the Hardened Containment Venting System upstream of and including the outboard primary containment isolation valve also serves a Primary Containment System function.

The portion of the Hardened Containment Venting System upstream of and including the outboard primary containment isolation valve is addressed in Section 2.3.2.1, Containment System. The portion of the Hardened Containment Venting System downstream of the outboard primary containment isolation valve is addressed in this Section.

The Hardened Containment Venting System is described in FSAR Section 5.2.8. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Relied upon 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). The Hardened Containment Venting System is credited in the Fire PRA model to remove decay heat to meet NSPC Decay Heat Removal performance criteria. 10 CFR 54.4(a)(3)

FSAR References

Section 5.2.8

Subsequent License Renewal Boundary Drawings

1-47E865-18-SLR

2-47E865-18-SLR

3-47E865-18-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.3-38, Hardened Containment Venting System.

Table 2.3.3-38, Hardened Containment Venting System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
External surfaces	Pressure Boundary
Piping, piping components	Pressure Boundary

The aging management review results for these components are provided in Table 3.3.2-38, Hardened Containment Venting System - Summary of Aging Management Evaluation.

2.3.4 Steam and Power Conversions Systems

The following systems are addressed in this section:

- Main Steam System (2.3.4.1)
- Condensate/Demineralized Water System (2.3.4.2)
- Reactor Feedwater System (2.3.4.3)
- Heater Drains and Vents System (2.3.4.4)
- Miscellaneous Turbine Connections System (2.3.4.5)
- Condenser Circulating Water System (2.3.4.6)
- Gland Seal Water System (2.3.4.7)

2.3.4.1 Main Steam System

Description

The Main Steam System provides steam from the reactor vessel through the primary containment to the high pressure turbine over the full range of reactor power operation. Four steam lines are utilized between the reactor vessel and the high pressure turbine. The Main Steam System provides steam on demand to the HPCI System and RCIC System turbines via main steam lines.

Overpressure protection of the reactor vessel is provided via the main steam safety relief valves. This function ensures the integrity of the reactor coolant pressure boundary and associated piping.

The Main Steam System also includes the ADS which is an ECCS. Six designated MSRVs fulfill the ECCS function to ensure that the low pressure ECCS provide adequate core cooling during accident and post-accident conditions in the event that the high pressure coolant injection systems are unavailable or unable to maintain level in the vessel.

The Main Steam System operates in conjunction with the primary containment isolation system to mitigate the consequences of accidents which could result in potential offsite exposure due to a breach of the main steam system. The MSIVs will close on signals indicative of a LOCA or leak in the Main Steam System to containment. he main steam line flow restrictors limit the loss of coolant from the reactor coolant pressure boundary prior to MSIV closure following a main steam line rupture outside of containment. In the event that a main steam line rupture occurs inside the primary containment, closure of the isolation valve outside the containment acts to seal the primary containment itself.

Post-accident holdup and plateout of MSIV bypass leakage is credited in accident analyses when calculating airborne activities. Plateout and holdup are credited in the main steam line piping for a LOCA.

The Main Steam System is described in FSAR Sections 4.4, 4.5, 4.6, 4.11, 6.4.2, 6.5, and 7.4. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide emergency heat removal from primary containment and provide containment pressure control. The MSRV discharge quenchers condense the steam from MSRV operation to minimize pressure and thermal effects on the primary containment during plant events. 10 CFR 54.4(a)(1)
2. Sense process conditions and generate signals for reactor trip or engineered safety functions. The ADS uses drywell pressure, reactor water level sensor inputs and emergency core cooling pump pressure indication, arranged in trip systems, to initiate automatic depressurization. Additionally, Main Steam process conditions provide input signals to the Primary Containment Isolation System and the Reactor Protection System. 10 CFR 54.4(a)(1)
3. Provide reactor coolant pressure boundary. he Main Steam System forms a barrier to minimize the release of reactor coolant and radioactive material to the Reactor Building. The Main Steam System, in conjunction with the Reactor Protection System, provides overpressure protection for the reactor vessel and the Reactor Recirculation System. The main steam flow restrictors limit the loss of coolant from the reactor coolant pressure boundary prior to MSIV closure following a steam line rupture outside of containment. 10 CFR 54.4(a)(1)
4. Provide primary containment boundary. The Main Steam System includes piping and valves that are part of the primary containment boundary. 10 CFR 54.4(a)(1)
5. Provide support for emergency core cooling systems where the equipment provides cooling directly to the core. The ADS functions to depressurize the reactor vessel to allow low pressure emergency core cooling systems to inject if high pressure systems are unavailable. The Main Steam System also delivers steam to the HPCI and RCIC systems as a motive force for the turbines. 10 CFR 54.4(a)(1)
6. Provides secondary containment boundary. The Main Steam System includes piping and valves that are part of the secondary containment boundary. 10 CFR 54.4(a)(1)
7. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. The Main Steam System includes nonsafety-related components that maintain structural integrity of Main Steam System mechanical connections with reactor coolant pressure boundary and primary containment boundary. 10 CFR 54.4(a)(2)

8. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Main Steam System includes nonsafety-related fluid filled lines which have the potential for spatial interaction with safety-related components. 10 CFR 54.4(a)(2)
9. Directly support a safety-related function. The Main Steam System includes nonsafety-related piping and valves that is relied upon for providing an ALT path from outboard MSIVs to condenser. 10 CFR 54.4(a)(2)
10. Directly support a safety-related function. The Main Steam System includes nonsafety-related piping that is relied upon to preserve the structural integrity of the Secondary Containment boundary. 10 CFR 54.4(a)(2)
11. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). The Main Steam System provides a portion of the reactor coolant pressure boundary. 10 CFR 54.4(a)(3)
12. Portions of this system are relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). This system includes environmentally qualified electrical components. 10 CFR 54.4(a)(3)
13. Relied upon 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). 10 CFR 54.4(a)(3)
    - NSPC Inventory Control Performance Criteria: The ADS function of MSRVs depressurize the Reactor Coolant System. Depressurization facilitates using low pressure injection sources. The Main Steam System also delivers steam to the HPCI and RCIC systems as a motive force for the turbines. The Main Steam Isolation Valves in conjunction with the Turbine Stop Valves and Turbine Control Valves are evaluated in the Multiple Spurious Operation for inventory diversion flow path.
    - Provide reactor coolant pressure boundary. The Main Steam System forms a barrier to minimize the release of reactor coolant and radioactive material to the Reactor Building.
    - NSPC Pressure Control Performance Criteria: The Main Steam System, in conjunction with the Reactor Protection System, provides overpressure protection for the reactor vessel and the Reactor Recirculation System. MSRVs are also used to depressurize the reactor for NSPC Pressure Control Performance Criteria.
    - NSPC Decay Heat Removal Performance Criteria. MSRVs are used for alternate shutdown cooling flow path.
14. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Main Steam System provides the flow path and maintains the pressure boundary for reactor safe shutdown. The MSRV discharge quenchers condense the steam from MSRV operation to minimize pressure and thermal effects on the primary containment during station blackout. 10 CFR 54.4(a)(3)

<u>FSAR References</u>

Sections 4.1, 4.4, 4.5, 4.6, 4.11

Sections 5.2.3, 5.3

Sections 6.4.2, 6.5

Sections 7.2, 7.3, 7.4, 7.8, 7.10, 7.11, 7.12, 7.18
Section 11.5
Section 14.6
Appendix N

Subsequent License Renewal Boundary Drawings
1-47E801-1-SLR
1-47E801-2-SLR
2-47E801-1-SLR
2-47E801-2-SLR
3-47E801-1-SLR
3-47E801-2-SLR
1-47E817-1-SLR
1-47E1847-6-SLR
1-47E1847-10-SLR
1-47E807-1-SLR
1-47E807-2-SLR
2-47E2847-5-SLR
2-47E2847-9-SLR
2-47E807-1-SLR
2-47E807-2-SLR
3-47E3847-5-SLR
3-47E3847-9-SLR
3-47E807-1-SLR
3-47E807-2-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.4-1, Main Steam System.

Table 2.3.4-1, Main Steam System

Component Type	Passive Intended Functions
Closure Bolting • RCPB • Non-RCPB	Mechanical Closure
External Surfaces • Non-RCPB	Pressure Boundary, Holdup and Plateout

Table 2.3.4-1, Main Steam System (Continued)

Component Type	Passive Intended Functions
Insulated Piping, Piping Components, Tanks	Pressure Boundary
Piping, Piping Components • RCPB • Non-RCPB	Pressure Boundary, Throttle, Holdup and Plateout

The aging management review results for these components are provided in Table 3.4.2-1, Main Steam System - Summary of Aging Management Evaluation.

2.3.4.2 Condensate/Demineralized Water System

Description

The Condensate System provides treated water at required flow rates for the Feedwater System during normal plant operation. The Condensate System for each unit shares no components with the other units. The Condensate System for each unit consists of the condenser and piping to transfer water from the condenser to the Feedwater System. The condenser provides a heat sink for the closed loop steam cycle and removes non-condensable gases. The Condensate System has three motor-driven condensate pumps and three motor-driven condensate booster pumps. Impurities are removed by a full flow Demineralizer System. The water is heated by three sets of low pressure heaters. The Condensate System cools the steam jet air ejector intercondenser, the Off-Gas condenser, and the steam packing exhauster condenser. Major components are located in the turbine building

The condenser is credited in analyses for MSIV ALT.

Subsystems of the Condensate/Demineralized Water System are the Condensate Storage and Transfer System (radioactive high purity water) and the Demineralized Water System (non-radioactive high purity water). These are shared systems. The Condensate Water Storage Tanks that are the preferred source of water to the HPCI and RCIC Systems, provide a surge volume for flow testing of HPCI, RCIC and Core Spray Systems, provide condenser makeup, and a supply to the CRD System. The Condensate Water Storage Tanks and the Demineralized Water Storage Tank provide high purity water for miscellaneous makeup uses throughout the plant including flushing and filling of the RHR and Core Spray Systems within the Reactor Building. The tanks are located in the yard and major components are located in the Turbine Building.

The Condensate/Demineralized Water System is described in FSAR Sections 10.13, 11.8, 11.9, and Appendix F.6.10 and F.6.18. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide emergency core cooling where the equipment provides coolant directly to the core. The Condensate Storage System includes safety-related piping between the Condensate Water Storage Tanks and the HPCI and RCIC pumps. 10 CFR 54.4(a)(1)
2. Sense process conditions and generate signals for reactor trip or engineered safety features actuation. The Condensate Storage System includes safety-related level instrumentation that

provides a signal to realign the HPCI pump suction from the Condensate Water Storage Tanks to the suppression pool, when Condensate Water Storage Tanks water level reaches prescribed low level limits. 10 CFR 54.4(a)(1)

3. Provides primary containment boundary. The Condensate/Demineralized Water System includes piping and valves that are part of the primary containment boundary. 10 CFR 54.4(a)(1)
4. Provide system pressure boundary integrity. The Condensate Storage System includes piping that interfaces with the RHR System interfaces and separately with the Core Spray System that are required to maintain their pressure boundary integrity so as not to jeopardize the ability of the RHR System and the Core Spray System to perform their nuclear safety functions. 10 CFR 54.4(a)(1)
5. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Condensate/Demineralized Water System includes nonsafety-related fluid filled lines which have the potential for spatial interaction with safety-related components. 10 CFR 54.4(a)(2)
6. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. The Condensate/ Demineralized Water System includes nonsafety-related piping that is mechanically connected to safety-related piping for various systems in the Reactor Building. 10 CFR 54.4(a)(2)
7. Directly support a safety-related function. The nonsafety-related condenser is relied upon for holdup of leakage from the MSIVs for radioactive decay in the ALT analyses. 10 CFR 54.4(a)(2)
8. Directly support a safety-related function. The Condensate/Demineralized Water System includes nonsafety-related piping that is relied upon to preserve the structural integrity of the Secondary Containment safety-related function. 10 CFR 54.4(a)(2)
9. Relied upon 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). 10 CFR 54.4(a)(3)
    - The Condensate system is required to meet NSPC Inventory Control Performance Criteria.
    - Provide emergency core cooling where the equipment provides coolant directly to the core. The Condensate Storage System includes safety-related piping between the Condensate Water Storage Tanks and the HPCI and RCIC pumps.
    - The Condensate Storage System provides inventory for the EHPM pumps.
    - Condensate provides a source of water for low to medium pressure makeup to the reactor vessel. Water from the hotwell can be injected via the condensate and condensate booster pumps.
10. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the commission's regulations for Station Blackout (10 CFR 50.63). The Condensate Storage and Transfer System is the credited suction source for the HPCI and RCIC systems for Station Blackout coping and recovery. 10 CFR 54.4(a)(3)

<u>FSAR References</u>

Section 10.13

Sections 11.8, 11.9
Appendix F.6.10, F.6.18

Subsequent License Renewal Boundary Drawings
1-47E804-1-SLR
2-47E804-1-SLR
3-47E804-1-SLR
1-47E804-2-SLR
2-47E804-2-SLR
3-47E804-2-SLR
1-47E818-1-SLR
2-47E818-1-SLR
3-47E818-1-SLR
1-47E833-1-SLR
2-47E833-1-SLR
3-47E833-1-SLR
0-47E856-1-SLR
1-47E856-2-SLR
2-47E856-2-SLR
3-47E856-2-SLR
1-47E822-1-SLR
2-47E822-1-SLR
3-47E822-1-SLR
0-47E830-2-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.4-2, Condensate/Demineralized Water System.

Table 2.3.4-2, Condensate/Demineralized Water System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
External Surfaces	Filter, Holdup and Plateout, Pressure Boundary, Thermal Insulation Jacket Integrity
Heat Exchangers	Filter, Heat Transfer, Holdup and Plateout, Pressure Boundary, Thermal Insulation Jacket Integrity
Insulated Piping, Piping Components, Tanks	Pressure Boundary
Piping, Piping Components	Pressure Boundary
Tank	Pressure Boundary

The aging management review results for these components are provided in Table 3.4.2-2, Condensate/Demineralized Water System - Summary of Aging Management Evaluation.

2.3.4.3 Reactor Feedwater System

Description

The Reactor Feedwater System provides feedwater to the reactor to maintain a constant reactor water level. During normal plant operation, the Reactor Feedwater System receives its supply of water from the outlet of the condensate demineralizers. The system consists of three feedwater heater strings (with cascading drains) connected in parallel, each consisting of five low pressure feedwater heaters and one drain cooler in series. The feedwater heaters receive steam from the main turbine system and preheat feedwater prior to entering the reactor feed pumps, thus increasing the heat cycle efficiency. The outlets of the three heater strings are cross-connected and provide a common suction header for the three reactor feed pumps. The reactor feed pumps are mounted in parallel with each having an individual suction valve, discharge check valve, and discharge valve. The reactor feed pumps discharge to a common discharge header that connects to two feedwater headers. These two feedwater headers contain inboard and outboard primary containment isolation valves. Inside containment, these two feedwater headers each split into three piping runs for a total of six, which then go to the reactor vessel. The Reactor Feedwater System provides the injection path for HPCI and RCIC during transient and accident conditions. HPCI and RCIC join the Reactor Feedwater System outside the primary containment. Flow is then channeled through the feedwater piping to the reactor vessel.

The Reactor Feedwater System is described in FSAR Sections 4.11, 7.10 and 11.8. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provides reactor coolant pressure boundary. The Reactor Feedwater System includes piping and valves that are part of the reactor coolant pressure boundary. 10 CFR 54.4(a)(1)
2. Provide primary containment boundary. The Reactor Feedwater System includes piping and valves that are part of the primary containment boundary. 10 CFR 54.4(a)(1)
3. Provide emergency core cooling where the equipment provides coolant directly to the core. The Reactor Feedwater System provides an injection path into the reactor vessel for the HPCI System. 10 CFR 54.4(a)(1)
4. Remove residual heat from the Reactor Coolant System. The Reactor Feedwater System provides an injection path into the reactor vessel for the HPCI and RCIC Systems. 10 CFR 54.4(a)(1)
5. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Reactor Feedwater System includes nonsafety-related fluid filled lines which have the potential for spatial interaction with safety-related components. 10 CFR 54.4(a)(2)
6. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. The Reactor Feedwater System includes nonsafety-related piping that is relied upon to preserve the structural integrity of safety-related Reactor Feedwater System piping. 10 CFR 54.4(a)(2)

7. Directly support a safety-related function. The Reactor Feedwater System includes nonsafety-related piping that is relied upon to preserve the Secondary Containment safety-related function. 10 CFR 54.4(a)(2)
8. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). The Reactor Feedwater System provides a portion of the reactor coolant pressure boundary. 10 CFR 54.4(a)(3)
9. Portions of this system are relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). This system includes environmentally qualified electrical components. 10 CFR 54.4(a)(3)
10. Relied upon 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). 10 CFR 54.4(a)(3)
    - The Reactor Feedwater system is required to meet NSPC Inventory Control Performance Criteria.
    - Provides reactor coolant pressure boundary. The Reactor Feedwater System includes piping and valves that are part of the reactor coolant pressure boundary.
    - Provide emergency core cooling where the equipment provides coolant directly to the core. The Reactor Feedwater System provides an injection path into the reactor vessel for the HPCI, RCIC, Condensate and EHPM Systems to meet NSPC Inventory Control Performance Criteria.
11. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The Reactor Feedwater System provides an injection path into the reactor vessel for both HPCI and RCIC. In addition, the feedwater pump emergency bearing oil pumps are required to operate following a Station Blackout. 10 CFR 54.4(a)(3)

<u>FSAR References</u>

Section 3.7

Sections 4.2, 4.7.5, 4.9, 4.11

Sections 5.2.3, 5.3

Section 6.4.1

Section 7.2, 7.3, 7.4, 7.8, 7.10

Section 10.17

Section 11.8

Figure 11.8-1

<u>Subsequent License Renewal Boundary Drawings</u>

1-47E803-1-SLR

1-47E803-5-SLR

2-47E803-1-SLR

2-47E803-5-SLR

3-47E803-1-SLR

3-47E803-5-SLR

1-47E817-1-SLR
2-47E817-1-SLR
3-47E817-1-SLR
2-47E2847-9-SLR
3-47E3847-9-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.4-3, Reactor Feedwater System.

Table 2.3.4-3, Reactor Feedwater System

Component Type	Passive Intended Functions
Closure Bolting • RCPB • Non-RCPB	Mechanical Closure
External Surfaces • Non-RCPB	Pressure Boundary
Heat Exchangers	Pressure Boundary
Insulated Piping, Piping Components, Tanks	Pressure Boundary
Piping, Piping Components • RCPB • Non-RCPB	Pressure Boundary
Tanks	Pressure Boundary

The aging management review results for these components are provided in Table 3.4.2-3, Reactor Feedwater System - Summary of Aging Management Evaluation.

2.3.4.4 Heater Drains and Vents System

Description

The Heater Drains and Vents system supports feedwater heaters and drain coolers as follows. Each unit is provided with three parallel strings of feedwater heaters, each consisting of three low-pressure feedwater heaters and two high-pressure feedwater heaters. Condensate drainage from the drain coolers of each feedwater heater flows to the next lower-pressure heater by means of pressure differential between successive heaters. Condensate drainage exiting from the separate drain cooler of the lowest-pressure heater is returned to the condenser.

The entire set of piping and components that make up the Heater Drains and Vents system is located in the Turbine Building and is nonsafety-related. The piping and components are neither connected to or in the vicinity of safety-related components. However, a small portion of this system serves the unique safety-related function to provide the ALT path from the MSIVs to the condenser to limit release of radioactive materials to the environment.

The Heater Drains and Vents System is discussed in FSAR Section 11.8. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Directly support a safety-related function. The Heater Drains and Vents system includes nonsafety-related piping and valves that is relied upon for providing an ALT path from outboard MSIVs to condenser. 10 CFR 54.4(a)(2)

FSAR References

Section 11.8

Subsequent License Renewal Boundary Drawings

1-47E807-1-SLR

2-47E807-1-SLR

3-47E807-1-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.4-4, Heater Drains and Vents System.

Table 2.3.4-4, Heater Drains and Vents System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
External Surfaces	Pressure Boundary
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.4.2-4, Heater Drains and Vents System - Summary of Aging Management Evaluation.

2.3.4.5 Miscellaneous Turbine Connections System

Description

Miscellaneous Turbine Connections is a nonsafety-related system which directs controlled leakage from various MS System components to the condenser. Some of these components are credited in analyses for MSIV ALT. Since failure of nonsafety-related Miscellaneous Turbine Connections system components could prevent satisfactory accomplishment of safety-related functions, criterion 10 CFR 54.4(a)(2) is met.

Miscellaneous Turbine Connections are not described in the FSAR. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Directly support a safety-related function. Nonsafety-related Miscellaneous Turbine Connections system components are relied upon for holdup of leakage from the MSIVs for radioactive decay in the ALT analyses. 10 CFR 54.4(a)(2)

FSAR References

None

Subsequent License Renewal Boundary Drawings

1-47E807-1-SLR
2-47E807-1-SLR
3-47E807-1-SLR
1-47E807-2-SLR
2-47E807-2-SLR
3-47E807-2-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.4-5, Miscellaneous Turbine Connections System.

Table 2.3.4-5, Miscellaneous Turbine Connections System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
External Surfaces	Pressure Boundary
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.4.2-5, Miscellaneous Turbine Connections System - Summary of Aging Management Evaluation.

2.3.4.6 Condenser Circulating Water System

Description

The CCW System for each unit shares components with the other units. Each unit has three circulation water pumps that take water from a common intake channel in Wheeler Reservoir. After passing through the condensers the heated water is cooled by the cooling towers or discharged directly back to Wheeler Reservoir. Provisions (a loop in the discharge conduit with a vacuum breaker) are made for the prevention of backflow of heated water into the intake channel that serves as the ultimate heat sink if normal offsite power is lost. The CCW System for each unit normally operates independently, however a cross-tie is provided between the three CCW tunnels so that any one pump in an emergency can supply water to all units. One CCW pump has more than adequate capacity to dissipate the shutdown heat for the three units.

The CCW System is described in FSAR Sections 2.4.2.2.2, 11.6, 12.2.7, and Appendix F.6.4. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Prevent backflow to protect decay removal and cooling functions of safety-related systems. The CCW System provides manual vacuum breaking capability to prevent backflow from the cooling tower warm channel into the forebay upon trip of the CCW pumps. This capability protects the decay heat removal functions of the RHRSW System and the cooling functions of the EECW System post accident. 10 CFR 54.4(a)(1)
2. Resist spatial interaction of nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The CCW System includes nonsafety-related fluid filled lines in the Vacuum Pipe Building which have the potential for spatial interaction with safety-related vacuum breaker vent valves. 10 CFR 54.4(a)(2)
3. Resist structural interactions from mechanically connected nonsafety-related piping that could prevent satisfactory accomplishment of a safety-related function. The CCW System includes nonsafety-related piping that maintain structural integrity of mechanical connections with safety-related vacuum breaker vent valves. 10 CFR 54.4(a)(2)
4. Portions of this system are relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). This system includes environmentally qualified electrical components. 10 CFR 54.4(a)(3)
5. Relied upon 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). 10 CFR 54.4(a)(3)
   - The CCW System is a support system required to meet NSPC Vital Auxiliaries Performance Criteria.
   - Portions of the CCW System are considered in the NSCA due to the ability of CCW System to supply water to the RCW pumps. The CCW System supports the NSPC Vital Auxiliaries Performance Criteria.

FSAR References

Section 2.4.2.2.2

Section 11.6

Section 12.2.7

Appendix F.6.4

Subsequent License Renewal Boundary Drawings

1-47E831-1-SLR

2-47E831-1-SLR

3-47E831-1-SLR

1-47E831-3-SLR

2-47E831-3-SLR

3-47E831-3-SLR

1-47E857-1-SLR

2-47E857-1-SLR
3-47E857-1-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.4-6, Condenser Circulating Water System.

Table 2.3.4-6, Condenser Circulating Water System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
External Surfaces	Pressure Boundary
Piping, Piping Components	Pressure Boundary

The aging management review results for these components are provided in Table 3.4.2-6, Condenser Circulating Water System - Summary of Aging Management Evaluation.

2.3.4.7 Gland Seal Water System

Description

The Gland Seal Water System provides pressurized sealing water to condenser and Condensate System components that are under a vacuum to prevent air leakage into the condenser. The Gland Seal Water System for each unit shares no components with the other units. However, any unit's Gland Seal Tank may pressurize any other unit's system. The Gland Seal Water System for each unit has an elevated Gland Seal Tank located in the Reactor Building and associated piping that maintains a static pressure on seals (e.g., packing) of components of the main condenser and Condensate Systems that are under vacuum during normal plant operations.

The Gland Seal Water System is described in FSAR Section 9.5.4, Figures 1.6-2, and 1.6-11. The system boundaries for SLR are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. The Gland Seal Water system includes nonsafety-related fluid filled components in the Reactor Building which have the potential for spatial interaction with safety-related components. 10 CFR 54.4(a)(2)
2. Directly support a safety-related function. The Gland Seal Water System includes nonsafety-related piping that is relied upon to preserve the Secondary Containment safety-related function. 10 CFR 54.4(a)(2)

FSAR References

Section 5.3.3.5
Section 9.5.4
Figures 1.6-2, 1.6-11

Subsequent License Renewal Boundary Drawings

1-47E841-1-SLR

2-47E841-1-SLR

3-47E841-1-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.3.4-7, Gland Seal Water System.

Table 2.3.4-7, Gland Seal Water System

Component Type	Passive Intended Functions
Closure Bolting	Mechanical Closure
External Surfaces	Pressure Boundary
Piping, Piping Components	Pressure Boundary
Tanks	Pressure Boundary

The aging management review results for these components are provided in Table 3.4.2-7, Gland Seal Water System - Summary of Aging Management Evaluation.

2.4 SCOPING AND SCREENING RESULTS: STRUCTURES

The scoping and screening results for structures consist of lists of structures and structural commodities that require aging management reviews, that are grouped, and presented on a structure and commodity group basis. Brief descriptions of structures and structural commodities within the scope of subsequent license renewal are provided as background information. Structure and structural commodity intended functions are provided for in-scope structures and structural commodities.

The following structures and commodity groups are addressed in this section:

- Reactor Buildings (2.4.1)
- Primary Containment Structures (2.4.2)
- Diesel Generator Buildings (2.4.3)
- Intake Pumping Station (2.4.4)
- Reinforced Concrete Chimney (2.4.5)
- Standby Gas Treatment Building (2.4.6)
- Off-Gas Treatment Building (2.4.7)
- Equipment Access Lock (2.4.8)
- Vacuum Pipe Building (2.4.9)
- Turbine Buildings (2.4.10)
- Radwaste Building (2.4.11)
- Service Building (2.4.12)
- Vent Vaults (2.4.13)
- Gate Structure Number 2 (2.4.14)
- Gate Structure Number 3 (2.4.15)
- Discharge Control Structure (2.4.16)
- Circulating Water Conduits (2.4.17)
- Diesel High Pressure Fire Pump House (2.4.18)
- Low Level Radwaste Storage Facility (2.4.19)
- Transformer Yard (2.4.20)
- 161 kV Switchyard (2.4.21)
- 500 kV Switchyard (2.4.22)
- Condensate Water Storage Tanks Foundations, Trenches, and Tunnels (2.4.23)
- Nitrogen Storage Tank Foundation (2.4.24)
- Supplemental Diesel Generator Building (2.4.25)
- Containment Atmosphere Dilution System Storage Tank Foundation (2.4.26)
- Intake Channel (2.4.27)
- North Bank of Cool Water Channel East of Gate Structure Number 2 (2.4.28)
- South Dike of Cool Water Channel between Gate Structures Number 2 and Number 3 (2.4.29)
- Earth Berm (2.4.30)
- Residual Heat Removal Service Water Tunnel (2.4.31)
- Electrical Cable Tunnel (from Intake Pumping Station to Powerhouse) (2.4.32)

- Underground Concrete Encased Structures (2.4.33)
- Yard, General (2.4.34)
- South Access Retaining Wall (2.4.35)
- Structural Commodities (2.4.36)
    - Cable Trays and Supports
    - Conduit and Conduit Supports
    - Electrical Panels, Racks, Cabinets, and other Enclosures
    - Equipment Supports and Foundations
    - Hazard Barriers and Elastomers
    - HVAC Duct Supports
    - Miscellaneous Steel
    - Penetrations and Sleeves
    - Pilings
    - Pipe Whip Restraints and Jet Impingement Shields
    - Piping Supports
    - Thermal Insulation
    - Tube Track
- Isolation Valve Pits (2.4.37)

2.4.1 Reactor Buildings

Description

The Reactor Building for each unit completely encloses the reactors, the primary containment structures, and the auxiliary and emergency systems of the nuclear steam supply system. A major sub-structure of the Reactor Building is the reinforced concrete biological shield that surrounds the drywell portion of primary containment. The Reactor Buildings also house features such as the spent fuel pool, steam dryer/moisture separator storage pool, reactor cavity, reactor auxiliary equipment, refueling equipment, reactor servicing equipment, and the Control Bay. The Control Bay houses the main control room for plant operation and other important auxiliary systems required for plant operation. The Reactor Building consists of monolithic reinforced concrete floors and walls from its foundation to the refueling floor. The refueling floor, which is common for all three units, is enclosed by the steel superstructure with metal siding and a built-up roof. Blowout or pressure relief panels are installed as part of the Reactor Building superstructure metal siding to relieve pressure during a DBA or DBE. The Reactor Buildings are an overall integral part of the Fire Protection Program and essential to the NFPA 805 NSCA Performance Goals.

Components not included in the evaluation boundary of the Reactor Buildings are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

Roof downspouts drains are evaluated with the Station Drainage System. The Reactor Building cranes and other miscellaneous cranes are evaluated with the Cranes and Hoists System and Fuel Handling and Storage System. Ventilation components, such as dampers and ducting, are evaluated with the ventilation systems. In addition, other mechanical and electrical systems and components housed in or located within the boundary of the Reactor Building are evaluated with their respective mechanical and electrical subsequent license renewal systems or commodities groups.

The Reactor Buildings are described in FSAR Figure 2.2-4, Sections 5.3 and 12.2.2, and Appendices F.7.1, F.7.2, and F.7.3. The structures are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide physical support, shelter, and protection for safety-related SSCs. 10 CFR 54.4(a)(1)
2. Provide physical support, shelter, and protection for nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of safety-related systems intended function(s). 10 CFR 54.4(a)(1)
3. Provide protection for safe storage of new and spent fuel. 10 CFR 54.4(a)(1)
4. Control the potential release of fission products to the external environment so that offsite consequences of DBEs are within acceptable limits. 10 CFR 54.4(a)(1)
5. Provide for the discharge of treated gaseous waste to meet the requirements of 10 CFR 50.67 or 10 CFR 100. 10 CFR 54.4(a)(1)
6. Prevent liquid radioactive waste from being released to the environment in the event of a Safe Shutdown Earthquake. 10 CFR 54.4(a)(1)
7. Prevent criticality of fuel assemblies stored in the spent fuel pool. 10 CFR 54.4(a)(1)
8. Provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient without Scram (10 CFR 50.62). 10 CFR 54.4(a)(3)
9. Portions of this structure/component support provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). 10 CFR 54.4(a)(3)
10. Provide physical support, shelter, and protection for SSCs relied upon 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). 10 CFR 54.4(a)(3)
11. Provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

FSAR References

Figure 2.2-4

Section 5.3

Section 12.2.2

Appendices F.7.1, F.7.2, F.7.3

Subsequent License Renewal Boundary Drawings
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Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-1, Reactor Buildings.

Table 2.4-1, Reactor Buildings

Component Type	Passive Intended Functions
Concrete: (Accessible Areas): All Concrete: (Accessible Areas): Above Grade Exterior Concrete: (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete: (Accessible Areas): Exterior Below Grade; Foundation Concrete: (Accessible Areas): Interior Concrete: (Inaccessible Areas): All Concrete: (Inaccessible Areas): Below Grade Exterior; Foundation Concrete: (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete: (Inaccessible Areas): Foundation Concrete: Above Grade Exterior Concrete: All Concrete: Interior	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier, HELB Shielding
Masonry Walls: Interior	Shelter and Protection, Shielding, Structural Support
Polyurethane Foam Between the Drywell and the Reactor Building Concrete	Expansion/Separation
Stainless Steel Fuel Pool Liner Spent Fuel Pool Gates Spent Fuel Pool Gates Bolting	Structural Support
Steel Components: All Structural Steel	Structural Support, Shelter and Protection, Pressure Boundary
Structural Bolting	Structural Support

The aging management review results for these components are provided in Table 3.5.2-1, Reactor Buildings - Summary of Aging Management Evaluation.

2.4.2 Primary Containment Structures

Description

The Primary Containment structures are a General Electric Mark I containment design. The primary containment for each unit consists of a drywell, pressure suppression chamber and a connecting vent system. The Primary Containment structure for each unit is completely enclosed within each unit's Reactor Building.

The drywell is a steel pressure vessel enclosed in reinforced concrete. The drywell contains the reactor vessel, the reactor recirculation system, and portions of other systems that form the reactor coolant pressure boundary. It also includes structural steel framing, electrical and mechanical equipment and system supports, a concrete shield wall around the reactor vessel, a removable steel head, a personnel airlock with two mechanically interlocked doors, two equipment hatches, and miscellaneous electrical and mechanical penetrations.

The pressure suppression chamber is a steel toroidal shaped pressure vessel. The pressure suppression chamber is commonly known as the torus. The torus includes internal steel framing, vent header, supports, access hatches, and penetrations. The torus is mounted on support structures that transmit loads to the concrete foundation of the Reactor Building.

The drywell is connected to the pressure suppression chamber with eight equally spaced vent lines. These drywell vent lines are connected to a header which is contained within the air space of the pressure suppression chamber. The pressure suppression chamber contains a large pool of water that condenses steam from a failure of reactor coolant pressure boundary piping in the drywell. The pool also condenses steam from MSRV discharge, and HPCI and RCIC turbine discharge.

The Primary Containment structure limits the release of fission products to the environment in the event of a design basis LOCA.

Components not included in the evaluation boundary of the Primary Containment Structures are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The containment isolation valves are evaluated in the Primary Containment Isolation System. Ventilation components, such as dampers and ducting, are evaluated with the ventilation systems. In addition, other mechanical and electrical systems and components housed in or located within the boundary of the Containment Structure are evaluated with their respective mechanical and electrical subsequent license renewal systems or commodities group. The reinforced concrete structures that enclose the drywell for shielding purposes, such as the drywell shield wall and shield plugs at the top of the reactor well, are evaluated with the Reactor Building.

The Primary Containments are an overall integral part of the Fire Protection Program and essential to the NFPA 805 NSCA Performance Goals. The Primary Containments prevents excessive radioactive release and supports the Fire Probabilistic Risk Assessment (FPRA) Large Early Release Frequency (LERF) metric.

The Primary Containment structures are described in FSAR Figure 5.2-1a, Sections 5.2.3 and 12.2.2, and Appendix C.5.The structures are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provides physical support, shelter, and protection for safety-related systems and components. 10 CFR 54.4(a)(1)
2. Provides physical support, shelter, and protection for nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of safety-related system intended function(s). 10 CFR 54.4(a)(1).
3. Provides primary containment boundary. 10 CFR 54.4(a)(1)
4. Limits and controls the release of fission products to the secondary containment and the external environment during DBAs so that offsite consequences are within acceptable limits. 10 CFR 54.4(a)(1)
5. Provides sufficient air and water volumes to absorb the energy released to the containment in the event of DBEs so that the pressure is within acceptable limits. 10 CFR 54.4(a)(1)
6. Provides a source of water for ECCS. 10 CFR 54.4(a)(1)
7. Provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient Without Scram (10 CFR 50.62). 10 CFR 54.4(a)(3)
8. Portions of this structure/component support provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). 10 CFR 54.4 (a)(3)
9. Provide physical support, shelter, and protection for SSCs relied upon 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). 10 CFR 54.4(a)(3)
   - Primary Containment Boundary is maintained as an inerted atmosphere such that fires are not required to be postulated when at-power.
   - Primary Containment is considered a Physical Analysis Unit (PAU) for non-power operational modes when it is no longer inerted.
   - The Primary Containment structure limits the release of fission products to the environs, and supports the FPRA LERF metric
10. Provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

FSAR References

Figure 5.2-1a

Section 5.2.3

Section 12.2.2

Appendix C.5

Subsequent License Renewal Boundary Drawings

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Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-2, Primary Containment Structures.

Table 2.4-2, Primary Containment Structures

Component Type	Passive Intended Functions
Concrete: (Accessible Areas): All Concrete: (Accessible Areas): Interior Concrete: (Inaccessible Areas): All Concrete: Interior Group 4: Concrete (Reactor Cavity Area Proximate To The Reactor Vessel): Reactor (Primary / biological) Shield Wall; Sacrificial Shield Wall; Reactor Vessel Support /pedestal Structure High Density Shielding Concrete	HELB Shielding, Shielding, Structural Support
Metal Liner, Metal Plate	Pressure Boundary, Structural Support, Shelter and Protection
Penetration Bellows	Expansion/Separation, Pressure Boundary
Personnel Airlock Personnel Airlock, Locks, Hinges, Closure Mechanisms	Pressure Boundary, Structural Support, Shelter and Protection
Pressure-retaining Bolting	Pressure Boundary, Structural Support
Service Level I Coatings	Maintain adhesion
Sliding Surfaces Sliding Surfaces: Graphite Impregnated Base Plates Sliding Surfaces: Radial Beam Seats in BWR Drywell	Structural Support
Steel Components: All Structural Steel	Structural Support
Steel Elements (Accessible Areas): Drywell Shell; Drywell Head; Drywell Shell In Sand Pocket Regions	Pressure Boundary, Shelter and Protection, Structural Support
Steel Elements: Downcomers Steel Elements: Drywell Head; Downcomers	Pressure Boundary, Shelter and Protection, Structural Support
Steel Elements: Drywell Support Skirt	Structural Support
Steel Elements: Refueling Bellows Assemblies Steel Elements: Refueling Bellows Support Skirt	Pressure Boundary, Water Retaining Boundary
Steel Elements: Torus Ring Girders Steel Elements: Torus Shell	Pressure Boundary, Structural Support, Water Retaining Boundary
Steel Elements: Torus Vent Header; Downcomers Steel Elements: Vent Header	Direct Flow, Pressure Boundary, Structural Support

Table 2.4-2, Primary Containment Structures (Continued)

Component Type	Passive Intended Functions
Structural Elements: Vent Line Bellows	Direct Flow, Expansion/Separation, Pressure Boundary, Structural Support
Structural Bolting	Structural Support

The aging management review results for these components are provided in Table 3.5.2-2, Primary Containment Structures - Summary of Aging Management Evaluation.

2.4.3 Diesel Generator Buildings

Description

The Units 1/2 Diesel Generator Building is a Class I concrete structure, located adjacent to the west side of the Reactor Building and the south side of the Radwaste Building. It is separated from these buildings by a two-inch expansion joint filled with fiberglass insulation. The south end of the building faces an earth backfill varying to a height of approximately 29 feet above the lower floor level. The west side of the building is exposed. The foundation for the structure is earth backfill. The structure is a two-story concrete box, with one longitudinal dividing wall full length and height, and four transverse dividing walls full height terminating at the longitudinal wall.

Built later, the Unit 3 Diesel Generator Building is also a Class I concrete structure and has the same configuration and foundation as that of the Units 1/2 Diesel Generator Building

Diesel Generator Buildings provide structural support and shelter/protection for the diesel generators and other in-scope components that are essential for safe shutdown in the event of a sustained loss of offsite power. The Units 1/2 Diesel Generator Building houses four diesel generators that provide power to the four shared Unit 1 and 2 shutdown boards located in the Reactor Buildings. The Unit 3 Diesel Generator Building houses four diesel generators that provide power to the four Unit 3 shutdown boards located in the Unit 3 Diesel Generator Building. The Diesel Generator Buildings are an overall integral part of the Fire Protection Program and essential to the NFPA 805 NSCA Performance Goals.

Components not included in the evaluation boundary of the Diesel Generator Buildings are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

Ventilation components, such as dampers and ducting, are evaluated with the ventilation systems.

The Diesel Generator Buildings are described in FSAR Figure 2.2-4, Sections 8.5, 12.2.8, and 12.2.13, and Appendix F.7.6.The structures are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provides physical support, shelter, and protection for safety-related SSCs. 10 CFR 54.4(a)(1)
2. Provide physical support, shelter, and protection for nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of safety-related system intended function(s). 10 CFR 54.4(a)(1)
3. Provide physical support, shelter, and protection for SSCs relied upon 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). 10 CFR 54.4(a)(3)
4. Provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

FSAR References

Figure 2.2-4

Section 8.5

Sections 12.2.8, 12.2.13

Appendix F.7.6

Subsequent License Renewal Boundary Drawings

0-10E201-01-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-3, Diesel Generator Buildings.

Table 2.4-3, Diesel Generator Buildings

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas): Above Grade Exterior Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Accessible Areas): Interior Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Below Grade Exterior; Foundation Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): Foundation Concrete: All Concrete: Above Grade Exterior Concrete: Interior	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support
Masonry Walls: All	Shelter and Protection, Structural Support

Table 2.4-3, Diesel Generator Buildings (Continued)

Component Type	Passive Intended Functions
Steel Components: All Structural Steel	Shelter and Protection, Structural Support
Structural Bolting	Structural Support

The aging management review results for these components are provided in Table 3.5.2-3, Diesel Generator Buildings - Summary of Aging Management Evaluation.

2.4.4 Intake Pumping Station

Description

The Intake Pumping Station is a reinforced concrete structure that provides structural support and shelter/protection for the condenser circulating water pumps, the electric fire pumps, and pumps supplying the RHRSW and EECW Systems. The Intake Pumping Station houses components for all three units. The Intake Pumping Station protects safety-related equipment and components such as the pumps supplying the RHRSW and EECW Systems from design basis events (e.g., earthquakes, flooding, tornadoes). The Intake Pumping Structure is an overall integral part of the Fire Protection Program and essential to the NFPA 805 NSCA Performance Goals.

Components not included in the evaluation boundary of the Intake Pumping Station are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

Ventilation components, such as dampers and ducting, are evaluated with the ventilation systems.

The Intake Pumping Station is described in FSAR Figure 2.2-4, Sections 12.2.7 and 12.2.16, and F.7.7. The structure is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide physical support, shelter, and protection for safety-related SSCs. 10 CFR 54.4(a)(1)
2. Provide a source of water for ECCS. 10 CFR 54.4(a)(1)
3. Provide physical support, shelter, and protection for nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of safety-related system intended function(s). 10 CFR 54.4(a)(1)
4. Provide physical support, shelter, and protection for SSCs relied upon 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). 10 CFR 54.4(a)(3)
5. Provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

FSAR References

Figure 2.2-4

Sections 12.2.7, 12.2.16

Appendix F.7.7

Subsequent License Renewal Boundary Drawings

0-10E201-01-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-4, Intake Pumping Station.

Table 2.4-4, Intake Pumping Station

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Accessible Areas): Foundation; Interior Slab Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Exterior Above Grade Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation; Interior Slab Concrete: All	Flood Barrier, Shelter and Protection, Structural Support
Masonry Walls: All	Shelter and Protection, Structural Support
Steel Components: All Structural Steel	Structural Support
Structural Bolting	Structural Support

The aging management review results for these components are provided in Table 3.5.2-4, Intake Pumping Station - Summary of Aging Management Evaluation.

2.4.5 Reinforced Concrete Chimney

Description

The Reinforced Concrete Chimney provides an elevated release point for radioactive gases from the gaseous radwaste processing systems during normal plant operations and from the Standby Gas Treatment System during secondary containment isolation and during primary containment venting. The Reinforced Concrete Chimney is an overall integral part of the Fire Protection Program and essential to the NFPA 805 NSCA Performance Goals.

The Reinforced Concrete Chimney is a single structure that serves all three units. The Reinforced Concrete Chimney is a 600-foot-high Class I structure designed so that Class I structures (with the exception of the Off-Gas Treatment building) will not be damaged during DBEs.

Components not included in the evaluation boundary of the Reinforced Concrete Chimney are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The Reinforced Concrete Chimney is described in FSAR Figure 2.2-4, Section 12.2.4, and Appendix F.7.14. The structure is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide physical support, shelter, and protection for safety-related SSCs. 10 CFR 54.4(a)(1)
2. Provide physical support, shelter, and protection for nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of safety-related. 10 CFR 54.4(a)(1)
3. Performs a function credited to demonstrate compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). 10 CFR 54.4(a)(3)
   - The Reinforced Concrete Chimney structure contains effluents and limits the release of radioactivity to the environment to satisfy NSPC Radioactive Release Performance Criteria.

FSAR References

Figure 2.2-4

Section 12.2.4

Appendix F.7.14

Subsequent License Renewal Boundary Drawings

0-10E201-01-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-5, Reinforced Concrete Chimney.

Table 2.4-5, Reinforced Concrete Chimney

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas): Above Grade Exterior Concrete (Accessible Areas): Interior Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Below Grade Exterior; Foundation Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): Foundation Concrete: All Concrete: Above Grade Exterior Concrete: Interior	Flood Barrier, Gaseous Release Path, Shelter and Protection, Structural Support
Masonry Walls: All	Shelter and Protection
Steel Components: All Structural Steel	Structural Support
Structural Bolting	Structural Support

The aging management review results for these components are provided in Table 3.5.2-5, Reinforced Concrete Chimney - Summary of Aging Management Evaluation.

2.4.6 Standby Gas Treatment Building

Description

The Standby Gas Treatment Building provides a protected environment for the Standby Gas Treatment System. The Standby Gas Treatment Building houses shared components for all three units. The Standby Gas Treatment Building consists of two double-barreled reinforced concrete box frame structures with closed ends. The two structures are located side-by-side adjacent to the southwest corner of the Unit 1 Reactor Building and lie within the Earth Berm. One structure house two of the three Standby Gas Treatment trains. The other structure houses the third Standby Gas Treatment train. The Standby Gas Treatment Building is an overall integral part of the Fire Protection Program and essential to the NFPA 805 NSCA Performance Goals.

Components not included in the evaluation boundary of the Standby Gas Treatment Building are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

Ventilation components, such as dampers and ducting, are evaluated with the ventilation systems.

The Standby Gas Treatment Building is described in FSAR Figure 2.2-4, Sections 5.3.3.7 and 12.2.10, and Appendix F.7.8. The structure is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide physical support, shelter, and protection for safety-related SSCs. 10 CFR 54.4(a)(1)
2. Provide physical support, shelter, and protection for nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of safety-related system intended function(s). 10 CFR 54.4(a)(1)
3. Portions of this structure/component support provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). 10 CFR 54.4(a)(3)
4. The Standby Gas Treatment Building performs a function credited to demonstrate compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). 10 CFR 54.4(a)(3)
    - The Standby Gas Treatment Building contains effluents and limits the release of radioactivity to the environment to satisfy NSPC Radioactive Release Performance Criteria.

FSAR References

Figure 2.2-4

Section 5.3.3.7

Section 12.2.10

Appendix F.7.8

Subsequent License Renewal Boundary Drawings

0-10E201-01-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-6, Standby Gas Treatment Building.

Table 2.4-6, Standby Gas Treatment Building

Component Type	Passive Intended Functions
Concrete (Accessible Areas): Above Grade Exterior Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Accessible Areas): Interior Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Below Grade Exterior; Foundation Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): Foundation Concrete: All Concrete: Above Grade Exterior Concrete: Interior	Flood Barrier, Shelter and Protection, Structural Support

The aging management review results for these components are provided in Table 3.5.2-6, Standby Gas Treatment Building - Summary of Aging Management Evaluation.

2.4.7 Off-Gas Treatment Building

<u>Description</u>

The Off-Gas Treatment Building is an underground structure that houses the Off-Gas System charcoal adsorbers and supporting equipment for all three units. The exterior walls and bottom slab are designed and constructed to maintain their structural integrity during a partial collapse of the Reinforced Concrete Chimney during an external event (seismic, tornadic, etc.) so that they will not permit water leakage into or out of the building below elevation 566.25 feet. The Off-Gas Treatment Building contains the effluents and limits the release of radioactivity to the environment during the fire and fire suppression activities.

Components not included in the evaluation boundary of the Off-Gas Treatment Building are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

Ventilation components, such as dampers and ducting, are evaluated with the ventilation systems.

The Off-Gas Treatment Building is described in FSAR Figure 2.2-4 and Section 12.2.14. The structure is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide physical support, shelter, and protection for safety-related SSCs. 10 CFR 54.4(a)(1)
2. Provide physical support, shelter, and protection for nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of safety-related system intended function(s). 10 CFR 54.4(a)(1)
3. The Off-Gas Treatment Building performs a function credited to demonstrate compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). 10 CFR 54.4(a)(3)
    - The Off-Gas Treatment Building contains effluents and limits the release of radioactivity to the environment during the fire and fire suppression activities.

FSAR References

Figure 2.2-4

Section 12.2.14

Subsequent License Renewal Boundary Drawings

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Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-7, Off-Gas Treatment Building.

Table 2.4-7, Off-Gas Treatment Building

Component Type	**Passive Intended Functions**
Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Accessible Areas): Interior Concrete (Accessible Areas): Above Grade Exterior Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Below Grade Exterior; Foundation Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): Foundation Concrete: All Concrete: Interior Concrete: Above Grade Exterior	Fission Product Barrier, Flood Barrier, Shielding, Shelter and Protection, Structural Support,
Masonry Walls: All	Shielding

The aging management review results for these components are provided in Table 3.5.2-7, Off-Gas Treatment Building - Summary of Aging Management Evaluation.

2.4.8 Equipment Access Lock

Description

The Equipment Access Lock is a concrete box structure approximately 26 feet wide by 26 feet high, extending outward from the south side of the Reactor Building approximately 106 feet. The structure is supported by a row of steel bearing piles to rock under each vertical wall, and another row at the midpoint of the ground level slab. In this manner, differential settlement and alignment problems are eliminated at the face of the rock-supported Reactor Building. The structure is covered to a depth of approximately three feet by the 30-foot-high earth berm which surrounds the reactor building. Separation from the Reactor Building is provided for by a two-inch expansion joint filled with fiberglass insulation.

The Equipment Access Lock contains effluents and limits the release of radioactivity to the environment during the fire and fire suppression activities.

Components not included in the evaluation boundary of the Equipment Access Lock are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The Equipment Access Lock is described in FSAR Figure 2.2-4, Sections 5.3.3.5 and 12.2.9. The structure is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide physical support, shelter, and protection for safety-related SSCs. 10 CFR 54.4(a)(1)
2. Provide physical support, shelter, and protection for nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of safety-related system intended function(s). 10 CFR 54.5(a)(1)
3. Provide secondary containment boundary. Limits and controls the release of fission products to the external environment during design basis accidents so that offsite consequences are within acceptable limits. 10 CFR 54.4(a)(1)
4. The Equipment Access Lock performs a function credited to demonstrate compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). 10 CFR 54.4(a)(3)
    - The Equipment Access Lock contains effluents and limits the release of radioactivity to the environment during the fire and fire suppression activities.

FSAR References

Figure 2.2-4

Section 5.3.3.5

Section 12.2.9

Subsequent License Renewal Boundary Drawings

0-10E201-01-SLR

<u>Components Subject to AMR</u>

The component types that require aging management review are indicated in the below Table 2.4-8, Equipment Access Lock.

Table 2.4-8, Equipment Access Lock

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Accessible Areas): Above Grade Exterior Concrete (Accessible Areas): Interior Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Below Grade Exterior; Foundation Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): Foundation Concrete: All Concrete: Above Grade Exterior Concrete: Interior	Pressure Boundary, Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support
Steel Components: All Structural Steel	Structural Support
Structural Bolting	Structural Support

The aging management review results for these components are provided in Table 3.5.2-8, Equipment Access Lock - Summary of Aging Management Evaluation.

2.4.9 Vacuum Pipe Building

<u>Description</u>

The Vacuum Pipe Building is an underground Class 1 structure that provides structural support and shelter/protection for the condenser circulating water system vacuum breaker components that prevent backflow from the warm water channel to the intake channel. This ensures that maximum temperature analysis assumptions for emergency cooling systems are maintained during accidents and events. The Vacuum Pipe Building is a shared feature for all three units. The Vacuum Pipe Building is identified as a NFPA 805 NSPC necessary structure for a system required to achieve safe and stable fuel conditions for any fire area in BFN.

The Vacuum Pipe Building is basically a single-barreled concrete box frame with closed ends. The below grade pipe building is located directly above the hump or steel lined siphon portion of the warm water conduits. Earth backfill covers the top of this building to a depth of about 2 feet. The building is founded on earth backfill.

Components not included in the evaluation boundary of the Vacuum Pipe Building are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip

Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The Vacuum Pipe Building is described in FSAR Figure 2.2-4 and Section 12.2.7.8.3. The structure is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide physical support, shelter, and protection for safety-related SSCs. 10 CFR 54.4(a)(1)
2. Provide physical support, shelter, and protection for SSCs relied upon 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). 10 CFR 54.4(a)(3)

FSAR References

Figure 2.2-4

Section 12.2.7.8.3

Subsequent License Renewal Boundary Drawings

0-10E201-01-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-9, Vacuum Pipe Building.

Table 2.4-9, Vacuum Pipe Building

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Below Grade; Foundation Concrete (Accessible Areas): Interior Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Below Grade Exterior; Foundation Concrete (Inaccessible Areas): Exterior Below Grade; Foundation Concrete (Inaccessible Areas): Foundation Concrete: All Concrete: Interior	Shelter and Protection, Structural Support

The aging management review results for these components are provided in Table 3.5.2-9, Vacuum Pipe Building - Summary of Aging Management Evaluation.

2.4.10 Turbine Buildings

Description

The Turbine Buildings are a common Class II structure consisting of a reinforced concrete structure with a steel superstructure. The buildings are compartmentalized with the primary consideration for the design of the walls being radiation shielding. The Turbine Buildings house the turbine generators (one for each unit) and other secondary equipment needed for power generation. The Turbine Buildings are an overall integral part of the Fire Protection Program and essential to the NFPA 805 NSCA Performance Goals.

In addition to the generators, the buildings house the turbines, condensers, other auxiliary systems and related piping. The Turbine Buildings are designed to not damage the Reactor Buildings when subjected to postulated loading conditions

The Turbine Building, below the operating floor, is a reinforced concrete framed structure supported on steel piles to bedrock. The Turbine Building, above the operating floor, is framed by transverse welded steel rigid frames. An expansion joint is provided between a 2-bay frame for Units 1/2 and a single-bay frame for Unit 3. These buildings house common services to all three units. For longitudinal expansion, the superstructure is provided with joints by using double rows of frames. Assurance that the Turbine Building will not damage the Reactor Building is provided by the inherent strength of that part of the Turbine Building that is adjacent to the Reactor Building.

Components not included in the evaluation boundary of the Turbine Buildings are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities. The building crane and other miscellaneous cranes and hoists are evaluated with the Cranes and Hoists System. Fire barriers (doors, dampers, fire rated enclosures, fire proofing material, penetration seals, fire barrier function of walls and slabs) are evaluated with the Fire Protection System. Mechanical and electrical systems and components housed inside the structure are separately evaluated with their respective mechanical systems, electrical systems, or commodities.

The Turbine Buildings are discussed in FSAR Figure 2.2-4, Section 12.2, and Appendix F.6.14. The structures are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provides structural support and shelter/protection for the main steam tunnel temperature switches and for the outboard MSIVs leakage pathway to condenser. 10 CFR 54.4(a)(2)
2. Not adversely impact other Class I structures as a result of a DBE. 10 CFR 54.4(a)(2)
3. Provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient without Scram (10 CFR 50.62). 10 CFR 54.4(a)(3)
4. Portions of this structure/component support provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that

demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). 10 CFR 54.4(a)(3)

5. Provide physical support, shelter, and protection for SSCs relied upon 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). 10 CFR 54.4(a)(3)
6. Provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

FSAR References

Figure 2.2-4

Section 12.2.3

Appendix F.6.14

Subsequent License Renewal Boundary Drawings

0-10E201-01-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-10, Turbine Buildings.

Table 2.4-10, Turbine Buildings

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Accessible Areas): Above Grade Exterior Concrete (Accessible Areas): Interior Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Below Grade Exterior; Foundation Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): Foundation Concrete: All Concrete: Above Grade Exterior Concrete: Interior	Shelter and Protection, Structural Support
Masonry Walls: All (Unit 2 only)	Structural Support
Steel Components: All Structural Steel	Structural Support
Steel Components: All Structural Steel	Shelter and Protection, Structural Support
Structural Bolting	Structural Support

The aging management review results for these components are provided in Table 3.5.2-10, Turbine Buildings - Summary of Aging Management Evaluation.

2.4.11 Radwaste Building

Description

The Radwaste Building houses common services to all three units. It is located adjacent to the Turbine Building, Service Building, Reactor Building, and Diesel Generator Building. The Radwaste Building is a Class II structure (excluding the exterior wall of the waste surge and waste collection tank room adjacent to the Diesel Generator Building) extending approximately 20 feet below grade and 30 feet above ground. It is isolated from the Reactor and Diesel Generator Buildings by a two-inch expansion joint filled with fiberglass insulation. The roof is mostly a steel framed structure except for the waste packing area, which consists of a concrete roof. The Radwaste Building is an overall integral part of the Fire Protection Program and essential to the NFPA 805 NSCA Performance Goals.

Components not included in the evaluation boundary of the Radwaste Building are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The Radwaste Building is described in FSAR Section 12.2.5. The structure is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provides structural support and shelter/protection for the Standby Gas Treatment System drain line to the off-gas condensate sump in the Radwaste Building. 10 CFR 54.4 (a)(2)
2. Provide physical support, shelter, and protection for SSCs relied upon 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). 10 CFR 54.4(a)(3)
    - The Radwaste Building contains effluents and limits the release of radioactivity to the environment to satisfy NSPC Radioactive Release Performance Criteria.

FSAR References

Section 12.2.5

Subsequent License Renewal Boundary Drawings

0-10E201-01-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-11, Radwaste Building.

Table 2.4-11, Radwaste Building

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Accessible Areas): Above Grade Exterior Concrete (Accessible Areas): Interior Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Below Grade Exterior; Foundation Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): Foundation Concrete: All Concrete: Above Grade Exterior Concrete: Interior	Flood Barrier, Shelter and Protection, Structural Support
Hatch	Shelter and Protection, Structural Support
Masonry Walls: All	Structural Support
Steel Components: All Structural Steel	Shelter and Protection, Structural Support
Structural Bolting	Structural Support

The aging management review results for these components are provided in Table 3.5.2-11, Radwaste Building - Summary of Aging Management Evaluation.

2.4.12 Service Building

Description

The nonsafety-related Class II Service Building consists of exterior concrete walls and footings with an interior structural steel frame supported by concrete footings. Concrete floor slabs are used. The structure is designed for applicable dead loads, wind loads, and floor live loads. Portions of the HPFP System that are relied upon for compliance with regulations for Fire Protection (10CFR 50.48) traverse through the Service Building. The HPFP System traverses through the Service Building and into the Radwaste Building and Turbine Building.

Components not included in the evaluation boundary of the Service Building are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The Service Building is described in FSAR Figure 2.2-4 and Section 12.2.6. The structure is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide physical support, shelter, and protection for SSCs relied upon 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). 10 CFR 54.4(a)(3)

FSAR References

Figure 2.2-4

Section 12.2.6

Subsequent License Renewal Boundary Drawings

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Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-12, Service Building.

Table 2.4-12, Service Building

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Accessible Areas): Above Grade Exterior Concrete (Accessible Areas): Interior Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Below Grade Exterior; Foundation Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): Foundation Concrete: All Concrete: Above Grade Exterior Concrete: Interior	Shelter and Protection, Structural Support
Masonry Walls: All	Structural Support
Steel Components: All Structural Steel	Shelter and Protection, Structural Support
Structural Bolting	Structural Support

The aging management review results for these components are provided in Table 3.5.2-12, Service Building - Summary of Aging Management Evaluation.

2.4.13 Vent Vaults

Description

A Vent Vault is provided for each unit. Each Vent Vault is an open-top concrete structure with its base foundation founded on compacted backfill located within the Earth Berm adjacent to its associated Reactor Building. The Vent Vaults contain components required for the Reactor Building Ventilation System supply, including the secondary containment isolation dampers.

Components not included in the evaluation boundary of the Vent Vaults are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The Vent Vault structures are shown on FSAR Figure 2.2-4. The structures are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Resist spatial interaction with safety-related dampers. 10 CFR 54.4(a)(2)

FSAR References

Figure 2.2-4

Subsequent License Renewal Boundary Drawings

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Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-13, Vent Vaults.

Table 2.4-13, Vent Vaults

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Accessible Areas): Above Grade Exterior Concrete (Accessible Areas): Interior Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Below Grade Exterior; Foundation Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): Foundation Concrete: All Concrete: Above Grade Exterior Concrete: Interior	Shelter and Protection, Structural Support

The aging management review results for these components are provided in Table 3.5.2-13, Vent Vaults - Summary of Aging Management Evaluation.

2.4.14 Gate Structure Number 2

Description

Gate Structure Number 2 is located in the cool water channel between the discharge control structure and the intake channel. The primary structural components of the gate structure are the concrete gravity section, the machinery deck, and the cellular cofferdams.

Components not included in the evaluation boundary of the Gate Structure Number 2 are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

Gate Structure Number 2 is discussed in FSAR Section 12.2.7. The structure is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide physical barrier to separate the warmer water discharged from the cooling towers during their operation with the water in the intake pumping station channel. This barrier function ensures that RHRSW makeup water does not exceed the design temperature limit. 10 CFR 54.4(a)(1)
2. Provide physical barrier to separate the warmer water discharged from the cooling towers during their operation with the water in the intake pumping station channel. This barrier function ensures that RHRSW makeup water does not exceed the design temperature limit.

RHRSW is required to meet NSPC Vital Auxiliaries and Decay Heat Removal Performance criterion. 10 CFR 54.4(a)(3)

FSAR References

Section 12.2.7

Subsequent License Renewal Boundary Drawings

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Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-14, Gate Structure Number 2.

Table 2.4-14, Gate Structure Number 2

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete: All	Shelter and Protection, Structural Support, Water Retaining Boundary
Steel Components: All Structural Steel	Structural Support

The aging management review results for these components are provided in Table 3.5.2-14, Gate Structure Number 2 - Summary of Aging Management Evaluation.

2.4.15 Gate Structure Number 3

Description

Gate Structure Number 3 is located at the south-east end of the plant, below the Intake Pumping Station and Intake Channel. The structure consists of a skimmer wall, machinery deck, gate guide cells, and gates. The gate guide cells consist of steel sheet piling driven to bedrock and filled with concrete. Gate Structure Number 3 is a common structure for all three units.

Gate Structure No. 3 acts as a skimmer wall for cooling water drawn from Wheeler Reservoir into the plant. Gate Structure No. 3 provides the protective safety function of supplying a source of cooling water to safety-related components. Gate Structure No. 3 is designed so that a sufficient flow of water from Wheeler Reservoir is provided to the Intake Channel to supply the RHRSW System and the EECW System.

Components not included in the evaluation boundary of the Gate Structure Number 3 are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip

Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

Gate Structure No 3 is described in FSAR Sections 11.6 and 12.2.7. The structure is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provides a source of cooling water to safety-related components. 10 CFR 54.4(a)(1)
2. Provide physical support, shelter, and protection for SSCs relied upon 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). 10 CFR 54.4(a)(3)
3. Provides physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). Provides a source of cooling water to safety-related components. 10 CFR 54.4(a)(3)

FSAR References

Section 11.6

Section 12.2.7

Subsequent License Renewal Boundary Drawings

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Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-15, Gate Structure Number 3.

Table 2.4-15, Gate Structure Number 3

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): Exterior Below Grade; Foundation Concrete: All Concrete: Exterior Above And Below Grade; Foundation	Structural Support
Steel Components: All Structural Steel	Structural Support
Structural Bolting	Structural Support

The aging management review results for these components are provided in Table 3.5.2-15, Gate Structure Number 3 - Summary of Aging Management Evaluation.

2.4.16 Discharge Control Structure

Description

The Discharge Control Structure is a nonsafety-related structure which has the intended function of distributing flow from the cool water channel to the discharge diffusers via Gate Structure Number 1 and to limit the potential overflowing of the safety-related Gate Structure Number 2 such that the ultimate heat sink is protected during periods of cooling tower operation. Gate Structure Number 2 provides the safety-related function of limiting the potential thermal mixing of the warmer water discharged from the cooling towers during their operation with the water in the intake pumping station channel which provides the makeup for the RHRSW System.

Components not included in the evaluation boundary of the Discharge Control Structure are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The Discharge Control Structure is described in FSAR Section 12.2.7. The structure is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Distribute flow from the cool water channel to the discharge diffusers via Gate Structure No. 1 to limit the potential overflowing of Gate Structure Number 2 such that the ultimate heat sink is protected during periods of cooling tower operation. 10 CFR 54.4(a)(2)

FSAR References

Section 12.2.7

Subsequent License Renewal Boundary Drawings

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Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-16, Discharge Control Structure.

Table 2.4-16, Discharge Control Structure

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): Exterior Grade; Foundation Concrete: All Concrete: Exterior Above And Below Grade; Foundation	Shelter and Protection, Structural Support

The aging management review results for these components are provided in Table 3.5.2-16, Discharge Control Structure - Summary of Aging Management Evaluation.

2.4.17 Circulating Water Conduits

Description

The CCW System for each unit shares components with the other units. Each unit has three circulation water pumps that take water from a common intake channel in Wheeler Reservoir. After passing through the condensers the heated water is cooled by the cooling towers or discharged directly back to Wheeler Reservoir. Provisions (a loop in the discharge conduit with a vacuum breaker) are made for the prevention of backflow of heated water into the intake channel that serves as the ultimate heat sink if normal offsite power is lost. Each pump is installed in a separate suction well with entering water strained by trash racks and traveling screens, operating in parallel. Each pump discharge is equipped with motor-operated butterfly valves. The discharges of the three pumps are brought together in a steel trifurcation transition to a single tunnel. The water is channeled to the condenser by this tunnel. The conduits are constructed of reinforced concrete. The Circulating Water Conduits are credited in the NFPA 805 NSCA to support the CCW System intended function to supply water to the RCW system.

Components not included in the evaluation boundary of the Circulating Water Conduits are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

Circulating Water Conduits are described in FSAR Sections 2.4.2.2.2, 11.6, and 12.2.7.7, and Appendix F.6.4. The structures are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide physical support, shelter, and protection for systems, structures, and components relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Fire Protection (10 CFR 50.48). 10 CFR 54.4(a)(3)

FSAR References

Section 2.4.2.2.2

Section 11.6

Section 12.2.7.7

Appendix F.6.4

Subsequent License Renewal Boundary Drawings

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Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-17, Circulating Water Conduits.

Table 2.4-17, Circulating Water Conduits

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas):; Foundation; Interior Slab Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Exterior Below Grade; Foundation; Interior Slab Concrete: All Concrete: Exterior Below Grade; Foundation; Interior Slab	Structural Support, Water Retaining Boundary
Steel Components: All Structural Steel	Structural Support

The aging management review results for these components are provided in Table 3.5.2-17, Circulating Water Conduits - Summary of Aging Management Evaluation.

2.4.18 Diesel High Pressure Fire Pump House

Description

The Diesel High Pressure Fire Pump House is located at elevation 565 feet adjoining safety-related Gate Structure No. 2 where the diesel fire pump takes its suction from the cool water channel. The Diesel High Pressure Fire Pump House is a non-category I structure consisting of a steel frame structure and concrete.

The HPFP System supplies water for required water suppression systems, hydrants, and hose stations within the power block. The HPFP water supply system at BFN consists of one diesel engine driven and three electric motor driven fire pumps and water distribution piping. The one diesel engine driven fire pump is located in Diesel High Pressure Fire Pump House. The Diesel High Pressure Fire Pump House is a shared structure for all three units.

Components not included in the evaluation boundary of the Diesel High Pressure Fire Protection House are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The Diesel High Pressure Fire Pump House is shown on FSAR Figure 2.2-4. The structure is shown in the subsequent license renewal boundary drawings listed below.

<u>Intended Functions</u>

1. Resist spatial interactions from nonsafety-related SSCs that could prevent satisfactory accomplishment of a safety-related function. A failure of the Diesel High Pressure Fire Pump House could adversely affect the structural integrity of safety-related Gate Structure Number 2. 10 CFR 54.4(a)(2)
2. Provide physical support, shelter, and protection for SSCs relied upon 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). 10 CFR 54.4(a)(3)

<u>FSAR References</u>

Figure 2.2-4

<u>Subsequent License Renewal Boundary Drawings</u>

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<u>Components Subject to AMR</u>

The component types that require aging management review are indicated in the below Table 2.4-18, Diesel High Pressure Fire Pump House.

Table 2.4-18, Diesel High Pressure Fire Pump House

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Accessible Areas): Above Grade Exterior Concrete (Accessible Areas): Interior Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete: Above Grade Exterior Concrete: Interior	Shelter and Protection, Structural Support
Steel Components: All Structural Steel	Shelter and Protection, Support and Protection
Structural bolting	Structural Support

The aging management review results for these components are provided in Table 3.5.2-18, Diesel High Pressure Fire Pump House - Summary of Aging Management Evaluation.

2.4.19 Low Level Radwaste Storage Facility

<u>Description</u>

The Low Level Radwaste Storage Facility includes four modules. Only module numbers 1 and 2 are usable and within the scope of subsequent license renewal. The modules are designed for long-term storage of low level radioactive waste. The modules are segmented into compartments. The modules are above ground, safety-related structures constructed of reinforced concrete. Access to the modules is provided only from above and is primarily used for placing low level radwaste in or removing low level radwaste from the modules.

Each module is normally closed. Each module has five solid sides, and the only access point is the solid concrete top section. The modules have no moving parts or electrical components. No ventilation equipment is installed within the modules.

Each module contains a sump, with a through wall stainless steel pipe that is valved and blank flanged. This configuration allows for sampling of any potential drainage from materials. The physical structure, internal sump, and secured drain point provide engineering controls to prevent leakage from the module. By design, the module will contain the effluent in the event of a fire.

The Low Level Radwaste Storage Facility structure is not required to serve any safety functions directly related to safe shutdown of the reactors. The storage modules are safety related structures and are designed to resist loads resulting from extreme environmental events, such as high winds, tornadoes, and seismic events.

Components not included in the evaluation boundary of the Low Level Radwaste Storage Facility are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe

Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The Low Level Radwaste Storage Facility are discussed in the FSAR Sections 9.3.4.2.1 and 12.2.17. The structures are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide physical support, shelter, and protection for the storage modules and their contents to prevent or mitigate a significant offsite release of radioactivity. 10 CFR 54.4(a)(1)
2. The Low Level Radwaste Storage Facility contains effluents and limits the release of radioactivity to the environment to satisfy NFPA 805 NSPC Radioactive Release Performance Criteria. 10 CFR 54.4(a)(3)

FSAR References

Section 9.3.4.2.1

Section 12.2.17

Subsequent License Renewal Boundary Drawings

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Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-19, Low Level Radwaste Storage Facility.

Table 2.4-19, Low Level Radwaste Storage Facility

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Accessible Areas): Above Grade Exterior Concrete (Accessible Areas): Interior Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Below Grade Exterior; Foundation Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): Foundation Concrete: All Concrete: Above Grade Exterior Concrete: Interior	Flood Barrier, Missile Barrier, Shielding
Steel Components: All Structural Steel	Structural Support
Structural Bolting	Structural Support

The aging management review results for these components are provided in Table 3.5.2-19, Low Level Radwaste Storage Facility - Summary of Aging Management Evaluation.

2.4.20 Transformer Yard

Description

The Transformer Yard is a shared feature for all three units. The plant electric power system consists of the main generators, the main step-up transformers, the USSTs, the CSSTs, the cooling tower transformers (CTTs), the batteries, and the electric distribution system. Under normal plant operating conditions, the main generators supply electrical power through isolated-phase buses to the main step-up transformers and the unit station service transformers which are physically located adjacent to the Turbine Building. The primaries of the USSTs are connected to the isolated-phase bus at a point between the load side of the generator breaker terminals and the low-voltage connection of the main transformers. The CSSTs and CTTs are located outside.

During normal operation, station auxiliary power is taken from the main generator through the unit station service transformers. During startup and shutdown, auxiliary power is supplied from the 500 kV system through the main transformers to the USST with the main generators isolated by the main generator breakers. Auxiliary power is also available through the two CSSTs which are fed from the 161 kV system. The Transformer Yard provides support for the main transformers by providing a power path from the 500 kV system to the plant. Electrical power distribution is required to support the NFPA 805 Vital Auxiliaries NSPC.

Components not included in the evaluation boundary of the Transformer Yard are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The BFN transformers are described in detail in FSAR Section 8.4. The Transformer Yard is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide physical support, shelter, and protection for SSCs relied upon 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). 10 CFR 54.4(a)(3)
2. Provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)
    - The BFN transformers that are credited for offsite power recovery following a Station Blackout, are located within the Transformer Yard.

FSAR References

Section 8.4

Subsequent License Renewal Boundary Drawings

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0-15E500-02-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-20, Transformer Yard.

Table 2.4-20, Transformer Yard

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Accessible Areas): Above Grade Exterior Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Below Grade Exterior; Foundation Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): Foundation Concrete: All Concrete: Above Grade Exterior	Structural Support
Steel Components: All Structural Steel	Structural Support
Structural Bolting	Structural Support

The aging management review results for these components are provided in Table 3.5.2-20, Transformer Yard - Summary of Aging Management Evaluation.

2.4.21 161 kV Switchyard

Description

The 161 kV Switchyard is a shared feature for all three units. The switchyard routes power from off-site transmission lines into BFN for on-site use. The 161 kV Switchyard is supplied by two 161 kV transmission lines. One of these lines connects to the Trinity 500-161 kV Substation, and the other connects to the Athens, Alabama, 161 kV Substation. The 161 kV Switchyard contains a series of structures including pull-off tower structures, switch support structures, potential transformer support structures, carrier current structures, and bus support structures.

Components not included in the evaluation boundary of the 161 kV Switchyard are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The 161 kV Switchyard is described in Sections 8.1, 8.3 and 8.4 and Appendix F.6.1. The switchyard is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The 161 kV Switchyard is utilized to restore offsite power following a Station Blackout. 10 CFR 54.4(a)(3)

FSAR References

Sections 8.1, 8.3, 8.4

Appendix F.6.1

Subsequent License Renewal Boundary Drawings

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Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-21, 161 kV Switchyard.

Table 2.4-21, 161 kV Switchyard

Component Type	Passive Intended Functions
Concrete (Accessible Areas): Above Grade Exterior Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Accessible Areas): Interior Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Below Grade Exterior; Foundation Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): Foundation Concrete: All Concrete: Above Grade Exterior Concrete: Interior	Shelter and Protection, Structural Support
Steel Components: All Structural Steel	Structural Support
Structural Bolting: Steel	Structural Support

The aging management review results for these components are provided in Table 3.5.2-21, 161 kV Switchyard - Summary of Aging Management Evaluation.

2.4.22 500 kV Switchyard

Description

The BFN Units 1, 2, and 3 generators are connected into an existing network supplying large load centers. All three units are tied into TVA's 500 kV transmission system via seven 500 kV transmission lines. The 161 kV Switchyard is supplied by two 161 kV transmission lines. The 500 kV and 161 kV Switchyards supply startup, running, and shutdown power through stepdown transformers. The 161 kV Switchyard also supplies the cooling tower power.

The 500 kV Switchyard includes seven line bays and three transformer bays. The 500 kV connections consist of one line to the Madison 500 kV Substation; two lines to the Trinity 500 kV Substation; one line to the Maury 500 kV substation; one line to the West Point 500 kV Substation; one line to the Union 500 kV Substation; and one line to the Limestone 500 kV Substation.

The basic function of the normal auxiliary electrical power system is to provide power for plant auxiliaries during startup, operation, and shutdown, and to provide highly reliable power sources for plant loads which are important to its safety. The Normal Auxiliary Power System is to furnish power to start up and operate all the station auxiliary loads necessary for plant operation, and to furnish normal and alternate sources of power for safe shutdown.

The 500 kV Switchyard includes cable trenches, duct banks and control buildings, towers and tower foundations between the power block and substations, and switchgear buildings. Electrical power distribution is required to support the NFPA 805 Vital Auxiliaries NSPC. The 500 kV Switchyard also provides support for the 500 kV equipment which is credited for offsite power restoration by transferring power from the 500 kV and 161 kV electrical grid to the plant.

Components not included in the evaluation boundary of the 500 kV Switchyard are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The 500 kV Switchyard is described in detail in FSAR Sections 8.3, 8.4, Appendix F.6.1. The switchyard is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide physical support, shelter, and protection for SSCs relied upon 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). 10 CFR 54.4(a)(3)
2. Relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). The 500 kV Switchyard provides support for equipment used to restore offsite power following a Station Blackout. 10 CFR 54.4(a)(3)

<u>FSAR References</u>
Sections 8.3, 8.4
Appendix F.6.1

<u>Subsequent License Renewal Boundary Drawings</u>
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<u>Components Subject to AMR</u>

The component types that require aging management review are indicated in the below Table 2.4-22, 500 kV Switchyard.

Table 2.4-22, 500 kV Switchyard

Component Type	Passive Intended Functions
Concrete (Accessible Areas): Above Grade Exterior Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Accessible Areas): Interior Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Below Grade Exterior; Foundation Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): Foundation Concrete: All Concrete: Above Grade Exterior Concrete: Interior	Shelter and Protection, Structural Support
Steel Components: All Structural Steel	Structural Support
Structural Bolting	Structural Support

The aging management review results for these components are provided in Table 3.5.2-22, 500 kV Switchyard - Summary of Aging Management Evaluation.

2.4.23 Condensate Water Storage Tanks Foundations, Trenches, and Tunnels

<u>Description</u>

The Condensate Water Storage Tanks Foundations, Trenches, and Tunnels are shared features for all three units. The Condensate Water Storage Tank transfer piping is routed through reinforced concrete trenches and tunnels that provide physical support, shelter, and protection for condensate transfer piping routed to and from the Condensate Water Storage Tanks. There are five Condensate Water Storage Tanks. The two 500,000 gallon capacity tanks are not in-scope, and the three 375,000 gallon capacity tanks are in-scope. Each of the three in-scope Condensate Water Storage Tanks is supported on a foundation consisting of a concrete ring, under the perimeter of the tank bottom, which surrounds a bed of compacted sand. The 500,000 gallon Condensate Water Storage Tanks are supported on concrete slab foundations; However, the foundations for the 500,000 gallon Condensate Water Storage Tanks are not in-scope for subsequent licensing renewal.

The Condensate Water Storage Tanks provide the preferred source of water supply to the HPCI and RCIC Systems. The Condensate Water Storage Tanks also serve as a suction source for multiple systems required to meet the NFPA 805 Inventory Control NSPC.

Components not included in the evaluation boundary of the Condensate Water Storage Tanks Foundations, Trenches, and Tunnels are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The Condensate Water Storage Tanks Foundations, Trenches, and Tunnels are not discussed in the FSAR. The structures are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide physical support, shelter, and protection for SSCs relied upon 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). 10 CFR 54.4(a)(3)
2. Provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). Provides structural support for the Condensate Water Storage Tanks. 10 CFR 54.4(a)(3)

FSAR References

None

Subsequent License Renewal Boundary Drawings

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Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-23, Condensate Water Storage Tanks Foundations, Trenches, and Tunnels.

Table 2.4-23, Condensate Water Storage Tanks Foundations, Trenches, and Tunnels

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Below Grade Exterior; Foundation Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): Foundation Concrete: All Concrete: Above Grade Exterior	Shelter and Protection, Structural Support
Earthfill (Rock and Sand)	Structural Support
Steel Components: All Structural Steel	Structural Support
Structural Bolting	Structural Support

The aging management review results for these components are provided in Table 3.5.2-23, Condensate Water Storage Tanks Foundations, Trenches, and Tunnels - Summary of Aging Management Evaluation.

2.4.24 Nitrogen Storage Tank Foundation

Description

The Nitrogen Storage Tank Foundation is a reinforced concrete slab that provides structural support for the Nitrogen Storage Tank. The Nitrogen Storage Tank Foundation is part of the Containment Inerting System which is used during the initial purging of the primary containment and provides a supply of makeup nitrogen. The system consists of two liquid nitrogen storage tanks with two makeup vaporizers, a common purge vaporizer, pressure reducing valves and controllers, instrumentation valves and piping. Nitrogen is supplied from the common onsite storage tanks through the common purge vaporizer or makeup vaporizers where the liquid nitrogen is converted to the gaseous state. The Nitrogen Storage Tank Foundations provide support for the Nitrogen Storage Tanks, which are credited to demonstrate compliance with Fire Protection regulated events.

Components not included in the evaluation boundary of the Nitrogen Storage Tank Foundation are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The Nitrogen Storage Tank Foundation is not discussed in FSAR. The structure is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide physical support, shelter, and protection for SSCs relied upon 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). 10 CFR 54.4(a)(3)

FSAR References

None

Subsequent License Renewal Boundary Drawings

0-10E201-01-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-24, Nitrogen Storage Tank Foundation.

Table 2.4-24, Nitrogen Storage Tank Foundation

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Below Grade Exterior; Foundation Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): Foundation Concrete: All Concrete: Above Grade Exterior	Structural Support

The aging management review results for these components are provided in Table 3.5.2-24, Nitrogen Storage Tank Foundation - Summary of Aging Management Evaluation.

2.4.25 Supplemental Diesel Generator Building

Description

The Supplemental Diesel Generator Building houses two Supplemental Diesel Generator sets and associated supporting equipment on an elevated steel sub-base fuel tank. The Supplemental Diesel Generator building is a pre-fabricated, insulated metal walk-in structure. A reinforced concrete foundation is provided for the Supplemental Diesel Generator building and access galleries. The Supplemental Diesel Generators System is included in the NFPA 805 fire protection analysis to improve risk margin for CDF and LERF.

Components not included in the evaluation boundary of the Supplemental Diesel Generator Building are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe

Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The Supplemental Diesel Generator Building is described in FSAR Section 12.2.19. The structure is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide physical support, shelter, and protection for the Fire Protection system relied upon 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). 10 CFR 54.4(a)(3)

FSAR References

Section 12.2.19

Subsequent License Renewal Boundary Drawings

0-10E201-01-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-25, Supplemental Diesel Generator Building.

Table 2.4-25, Supplemental Diesel Generator Building

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Accessible Areas): Above Grade Exterior Concrete (Accessible Areas): Interior Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Below Grade Exterior; Foundation Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): Foundation Concrete: All Concrete: Above Grade Exterior Concrete: Interior	Shelter and Protection, Structural Support
Steel Components: All Structural Steel	Shelter and Protection, Structural Support
Structural Bolting	Structural Support

The aging management review results for these components are provided in Table 3.5.2-25, Supplemental Diesel Generator Building - Summary of Aging Management Evaluation.

2.4.26 Containment Atmosphere Dilution System Storage Tank Foundations

Description

The CAD System Storage Tank Foundations are reinforced concrete slabs on grade or foundations that provide structural support for the CAD System tanks. The CAD System tanks are used to control the concentration of combustible gases in the primary containment after an accident and to provide a backup pneumatic supply to selected components when the Control Air System is not available. The CAD System Storage Tank Foundations provide support for the CAD System Storage Tanks which are credited to demonstrate compliance with Fire Protection and Station Blackout regulated events.

Components not included in the evaluation boundary of the CAD System Storage Tank Foundations are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The CAD System Storage Tank Foundations are not discussed in the FSAR. The structures are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provides physical support and protection for safety-related SSCs. 10CFR54.4(a)(1)
2. Provide physical support, shelter, and protection for the Fire Protection system relied upon 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). 10 CFR 54.4(a)(3)
3. Provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

FSAR References

None

Subsequent License Renewal Boundary Drawings

0-10E201-01-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-26, Containment Atmosphere Dilution System Storage Tank Foundations.

Table 2.4-26, Containment Atmosphere Dilution System Storage Tank Foundations

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Below Grade Exterior; Foundation Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): Foundation Concrete: All Concrete: Above Grade Exterior	Structural Support

The aging management review results for these components are provided in Table 3.5.2-26, Containment Atmosphere Dilution System Storage Tank Foundations - Summary of Aging Management Evaluation.

2.4.27 Intake Channel

Description

The Intake Channel provides the following:

- A source of water to the condenser circulating water system and other plant cooling systems during normal operation.
- A source of cooling water post-transient and post-accident for decay heat removal, containment cooling, spent fuel cooling, control bay cooling, essential equipment cooling, and fire protection.
- A sufficient flow and heat sink capacity to maintain safe shutdown following a failure of the downstream Wheeler Dam.

The Intake Channel is common to all three units. The Intake Channel is an excavated channel that extends from the Intake Pumping Station into the river channel that would exist if the Wheeler Dam failed. The Intake Channel is a plant structure that supports the RHRSW System, which is credited to demonstrate compliance with Fire Protection and Station Blackout regulated events

Components not included in the evaluation boundary of the Intake Channel are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The Intake Channel is described in FSAR Sections 2.4.2 and 12.2.7 and Appendix F.7.7. The structure is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provides a source of cooling water to safety-related systems and components. 10 CFR 54.4(a)(1)
2. Provide physical support, shelter, and protection for the Fire Protection system relied upon 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). 10 CFR 54.4(a)(3)
3. Provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

FSAR References

Section 2.4.2

Section 12.2.7

Appendix F.7.7

Subsequent License Renewal Boundary Drawings

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Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-27, Intake Channel.

Table 2.4-27, Intake Channel

Component Type	Passive Intended Functions
Earthen Water-Control Structures: Dams; Embankments; Reservoirs; Channels; Canals	Structural Support

The aging management review results for these components are provided in Table 3.5.2-27, Intake Channel - Summary of Aging Management Evaluation.

2.4.28 North Bank of Cool Water Channel East of Gate Structure Number 2

Description

The North Bank of Cool Water Channel East of Gate Structure Number 2 is an earthen embankment on the north side of the cool water channel and south of the Reactor Buildings. The bank is a safety-related earthen structure with the sloped portion of the bank protected with vegetation and rock rip-rap. The bank is designed to support and protect the buried RHRSW System discharge piping located within the bank that discharges into Wheeler Reservoir. The North Bank of Cool Water Channel East of Gate Structure Number 2 is a structure relied on to provide physical support, in addition to shelter and protection, for the RHRSW piping, which is credited to demonstrate compliance with Fire Protection and Station Blackout regulated events.

Components not included in the evaluation boundary of the North Bank of Cool Water Channel East of Gate Structure Number 2 are Cable Trays and Supports; Conduit and Conduit Supports;

Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The North Bank of Cool Water Channel East of Gate Structure Number 2 is described in FSAR Section 12.2.7. The structure is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide physical support, shelter, and protection for safety-related SSCs. 10 CFR 54.4(a)(1)
2. Provide physical support, shelter, and protection for the Fire Protection system relied upon 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). 10 CFR 54.4(a)(3)
3. Provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

FSAR References

Section 12.2.7

Subsequent License Renewal Boundary Drawings

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Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-28, North Bank of Cool Water Channel East of Gate Structure Number 2.

Table 2.4-28, North Bank of Cool Water Channel East of Gate Structure Number 2

Component Type	Passive Intended Functions
Earthen Water-Control Structures: Embankments	Structural Support

The aging management review results for these components are provided in Table 3.5.2-28, North Bank of Cool Water Channel East of Gate Structure Number 2 - Summary of Aging Management Evaluation.

2.4.29 South Dike of Cool Water Channel between Gate Structures Number 2 and Number 3

Description

The South Dike of Cool Water Channel between Gate Structures Number 2 and Number 3 is an earthen dike on the south side of the cool water channel which forms a boundary with Wheeler Reservoir. The dike is a safety-related earthen structure with a sloped portion of the dike protected by vegetation and rock rip-rap. The dike is designed to protect the buried RHRSW System discharge piping located within the dike that discharges into Wheeler Reservoir. The South Dike of Cool Water Channel between Gate Structure Number 2 and Number 3 is a structure relied on to provide physical support, as well as shelter and protection, for the RHRSW piping, which is credited to demonstrate compliance with Fire Protection and Station Blackout regulated events.

Components not included in the evaluation boundary of the South Dike of Cool Water Channel between Gate Structures Number 2 and Number 3 are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The South Dike of Cool Water Channel between Gate Structures Number 2 and Number 3 is described in FSAR Figure 2.2-4 and Section 12.2.7. The structure is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide physical support, shelter, and protection for safety-related SSCs. 10 CFR 54.4(a)(1)
2. Provide physical support, shelter, and protection for the Fire Protection system relied upon 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). 10 CFR 54.4(a)(3)
3. Provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

FSAR References

Figure 2.2-4

Section 12.2.7

Subsequent License Renewal Boundary Drawings

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Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-29, South Dike of Cool Water Channel between Gate Structures Number 2 and Number 3.

Table 2.4-29, South Dike of Cool Water Channel between Gate Structures Number 2 and Number 3

Component Type	Passive Intended Functions
Earthen Water-Control Structures: Dams	Structural Support

The aging management review results for these components are provided in Table 3.5.2-29, South Dike of Cool Water Channel between Gate Structures Number 2 and Number 3 - Summary of Aging Management Evaluation.

2.4.30 Earth Berm

Description

The Earth Berm extends along the west, south, and east walls of the Reactor Building from the Unit 1/2 Diesel Generator Building to the Unit 3 Diesel Generator Building. The Earth Berm has the following structures located within it: Equipment Access Lock, the RHRSW Tunnels, Vent Vaults, and Standby Gas Treatment Building. The Earth Berm is a plant feature common to all three units.

Components not included in the evaluation boundary of the Earth Berm are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The Earth Berm is described in FSAR Section 12.2.9 and 12.2.10. The structure is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide physical support, shelter, and protection for safety-related SSCs. 10CFR 54.4(a)(1)

FSAR References
Sections 12.2.9, 12.2.10

Subsequent License Renewal Boundary Drawings
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Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-30, Earth Berm.

Table 2.4-30, Earth Berm

Component Type	Passive Intended Functions
Rock and Earthfill Embankment	Structural Support

The aging management review results for these components are provided in Table 3.5.2-30, Earth Berm - Summary of Aging Management Evaluation.

2.4.31 Residual Heat Removal Service Water Tunnels

Description

The RHRSW Tunnels are underground multi-plate arch tunnels that protect safety-related piping systems (i.e., RHRSW and EECW supply and discharge piping) that penetrate the south wall of the Reactor Building until they are buried below grade near the south end of the tunnels. The RHRSW Tunnels are safety related structures. The RHRSW Tunnels are structures relied on to provide physical support as well as shelter and protection for the RHRSW and EECW piping, which is credited to demonstrate compliance with Fire Protection regulated events.

Components not included in the evaluation boundary of the RHRSW Tunnels are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The RHRSW Tunnels are not described in the FSAR. The structures are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provides structural support and shelter/protection for safety-related components in the RHRSW Tunnels. 10 CFR 54.4(a)(1)
2. Provide physical support, shelter, and protection for the Fire Protection system relied upon 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). 10 CFR 54.4(a)(3)

FSAR References

None

Subsequent License Renewal Boundary Drawings

0-10E201-01-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-31, Residual Heat Removal Service Water Tunnels.

Table 2.4-31, Residual Heat Removal Service Water Tunnels

Component Type	Passive Intended Functions
Concrete (Accessible Areas): Above Grade Exterior Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Accessible Areas): Interior Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Below Grade Exterior; Foundation Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): Foundation Concrete: All Concrete: Above Grade Exterior Concrete: Interior	Shelter and Protection, Structural Support
Steel Components: All Structural Steel	Structural Support
Structural Bolting	Structural Support

The aging management review results for these components are provided in Table 3.5.2-31, Residual Heat Removal Service Water Tunnels - Summary of Aging Management Evaluation.

2.4.32 Electrical Cable Tunnel (from Intake Pumping Station to Powerhouse)

Description

The Electrical Cable Tunnel from the Intake Pumping Structure to the Powerhouse is an underground concrete-encased tunnel that provides structural support and shelter/protection for the power cables for components (including the RHRSW System, EECW System, and the electric fire pumps) in the Intake Pumping Station. A fire rated wall separates the Turbine Building from the electrical cable tunnel that routes to the Intake Pumping station.

The tunnel also runs east-west under the southern portion of the Turbine Buildings. The Electrical Cable Tunnel provides physical support as well as shelter and protection for the electric cables associated with RHRSW (Residual Heat Removal Service Water), EECW (Emergency Equipment Cooling Water), and CCW (Condenser Circulating Water) Systems in addition to the electric fire pumps, all of which are credited to demonstrate compliance with the Fire Protection regulated event. The Electric Cable Tunnel is also relied on to provide physical support as well as shelter and protection for safety-related systems, structures, and components, and power cables, for the RHRSW and EECW Systems, which are credited to demonstrate compliance with the Station Blackout regulated event.

Components not included in the evaluation boundary of the Electrical Cable Tunnel (from Intake Pumping Station to Powerhouse) are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping

Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The Electrical Cable Tunnel (from the Intake Pumping Structure to the Powerhouse) is discussed in FSAR Section 1.6.5.4. The structure is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide physical support, shelter, and protection for safety-related SSCs, power cables for the RHRSW System and EECW System. 10 CFR 54.4(a)(1)
2. Provide physical support, shelter, and protection for the Fire Protection system relied upon 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). 10 CFR 54.4(a)(3)
3. Provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

FSAR References

Section 1.6.5.4

Subsequent License Renewal Boundary Drawings

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Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-32, Electrical Cable Tunnel (from Intake Pumping Station to Powerhouse).

Table 2.4-32, Electrical Cable Tunnel (from Intake Pumping Station to Powerhouse)

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas): Interior Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Below-grade Exterior; Foundation Concrete: All Concrete: Interior	Shelter and Protection, Structural Support

The aging management review results for these components are provided in Table 3.5.2-32, Electrical Cable Tunnel (from Intake Pumping Station to Powerhouse) - Summary of Aging Management Evaluation.

2.4.33 Underground Concrete Encased Structures

Description

The Underground Concrete Encased Structures include safety-related manholes, handholes and duct banks that span between safety-related structures, manholes and handholes. This group of structures also includes those manholes, handholes, and duct banks required for Fire Protection and Station Blackout.

Components not included in the evaluation boundary of the Underground Concrete Encased Structures are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

Components in-scope for the Underground Concrete Encased Structures include:

- Safety-related concrete duct bank (inaccessible) that spans from the Intake Pumping Station to Handhole (HH)-15 to HH-26 and to the Electrical Cable Tunnel from the Intake Pumping Station to the Powerhouse
- Safety-related concrete duct bank (inaccessible) that spans from the Unit 1/2 Diesel Generator Building to the Standby Gas Treatment Building
- Safety-related concrete duct bank (inaccessible) that spans from the Unit 3 Diesel Generator Building to the Electrical Cable Tunnel from the Intake Pumping Station to the Powerhouse
- Safety-related concrete duct bank (inaccessible) that spans from the CAD Storage Tanks A and B foundations to the Reactor Building.
- Duct Banks associated with HH-1 through HH-13 (inaccessible) located in the Transformer Yard on the north side of the Turbine Building
- The concrete tunnel located in the 161 kV and 500 kV Switchyards
- Catch Basins 31, 32 and 33 located in the yard south of the Earth Berm.
- HH-1 through HH-13, HH-15, and HH-26 (RHRSW/EECW Division 1 Cables)
- Manholes (MH): MH-A, MH-B, MH-C and MH-D

Only the below grade portions of the associated structures are evaluated as part of Underground Concrete Encased Structures, all above grade portions of associated structures are evaluated as part of Yard Structures, General (see Section 2.4.34).

Underground Concrete Encased Structures are not discussed in FSAR. The structures are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide physical support, shelter, and protection for safety-related SSCs. 10 CFR 54.4(a)(1)
2. Provide physical support, shelter, and protection for the Fire Protection system relied upon 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). 10 CFR 54.4(a)(3)

3. Provide physical support, shelter, and protection for safety-related SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

FSAR References

None

Subsequent License Renewal Boundary Drawings

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Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-33, Underground Concrete Encased Structures.

Table 2.4-33, Underground Concrete Encased Structures

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Below Grade; Foundation Concrete (Accessible Areas): Interior Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Below Grade Exterior; Foundation Concrete (Inaccessible Areas): Exterior Below Grade; Foundation Concrete (Inaccessible Areas): Foundation Concrete: All Concrete: Interior	Shelter and Protection, Structural Support
Steel Components: All Structural Steel	Shelter and Protection, Structural Support

The aging management review results for these components are provided in Table 3.5.2-33, Underground Concrete Encased Structures - Summary of Aging Management Evaluation.

2.4.34 Yard Structures, General

Description

Yard Structures, General (Manholes, Duct Banks, etc.) includes various structures and components in the yard, inside of the Protected Area, around the power block and intake pumping station. The Yard Structures, General consist of various conduit duct banks, electrical and other manholes, valve pits, pipe tunnels and trenches, retaining walls, roads, storm drainage, lighting poles, storage tank foundations, and other miscellaneous yard features. Yard Structures determined to be in scope for subsequent license renewal are various electrical manholes which include the curbs, manhole access covers, and the buried duct banks that carry electrical cables in scope for subsequent license renewal. Other tank foundations, supports, pipe trenches, manholes, valve pits, roadways, lighting poles, storm drains, tunnels, and other components within the boundary of Yard Structures were evaluated and determined to be not in scope since the components do not perform an intended function.

Components not included in the evaluation boundary of the Yard Structures, General, which are in the yard area around the power block, are structural commodities, such as electrical panels, racks, cabinets, and other enclosures; conduit and conduit supports; cable trays and cable supports; and tube track; which are evaluated separately. Fire barriers (doors, dampers, fire rated enclosures, fire proofing material, penetration seals, fire barrier function of walls and slabs - including oil retaining dikes and walls that separate transformers) are evaluated with the Fire Protection System. Cable trenches, duct banks and control buildings in substations, towers and tower foundations between the power block and substations, and outdoor transformer foundations, and switchgear buildings are evaluated within the Transformer Yard, 161 kV Switchyard, and 500 kV Switchyard Structures. Any mechanical and electrical systems and components housed inside or supported by the Yard Structures, General or within any manhole or duct bank are separately evaluated with their respective mechanical systems, electrical systems, or commodities.

Only the above grade portions of the associated structures are evaluated as part of Yard Structures, General, all below grade portions of associated structures are evaluated as part of Underground Concrete Encased Structures (see Section 2.4.33).

Yard Structures, General is included in FSAR Table 10.11-1. Yard Structures, General is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provides physical support, shelter, and protection for safety-related SSCs. 10 CFR 54.4(a)(1)
2. Provide physical support, shelter, and protection for nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). 10 CFR 54.4(a)(1) and 10CFR 54.4(a)(2)
3. Provide physical support, shelter, and protection for the Fire Protection system relied upon 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). 10 CFR 54.4(a)(3)

FSAR References

Table 10.11-1

Subsequent License Renewal Boundary Drawings

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Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-34, Yard Structures, General.

Table 2.4-34, Yard Structures, General

Component Type	Passive Intended Functions
Concrete (Accessible Areas): Above Grade Exterior Concrete (Accessible Areas): All Concrete (Accessible Areas): Foundation Concrete (Accessible Areas): Exterior Above Grade; Foundation Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Exterior Above Grade; Foundation Concrete (Inaccessible Areas): Foundation Concrete: All Concrete: Above Grade Exterior	Shelter and Protection, Structural Support

The aging management review results for these components are provided in Table 3.5.2-34, Yard Structures, General - Summary of Aging Management Evaluation.

2.4.35 South Access Retaining Walls

Description

The South Access Retaining Walls are located east of the Equipment Access Lock. The South Access Retaining Walls are required to support the Earth Berm which is classified as a safety-related structure.

Components not included in the evaluation boundary of the South Access Retailing Walls are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The South Access Retaining Walls are not discussed in FSAR. The structures are shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide physical support, shelter, and protection for safety-related SSCs; the Earth Berm. 10 CFR 54.4(a)(1)

FSAR References

None

Subsequent License Renewal Boundary Drawings

0-10E201-01-SLR

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-35, South Access Retaining Wall.

Table 2.4-35, South Access Retaining Wall

Component Type	Passive Intended Functions
Concrete (Accessible Areas): All Concrete (Accessible Areas): Exterior Above And Below Grade; Foundation Concrete (Accessible Areas): Above Grade Exterior Concrete (Inaccessible Areas): All Concrete (Inaccessible Areas): Below Grade Exterior; Foundation Concrete (Inaccessible Areas): Exterior Above And Below Grade; Foundation Concrete (Inaccessible Areas): Foundation Concrete: All Concrete: Above Grade Exterior	Shelter and Protection, Structural Support

The aging management review results for these components are provided in Table 3.5.2-35, South Access Retaining Wall - Summary of Aging Management Evaluation.

2.4.36 Structural Commodities

Description

Structural commodities include the following component groups: Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints and Jet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. The component groupings are based on similarities in design, material, aging effect, and environment.

- Cable Trays and Supports

  The Cable Tray and Supports commodity group includes components such as cable trays and cable tray covers. Components evaluated in this group include cable trays, and their structural support members, welds, bolting, anchorage and building concrete at anchorage, that comprise the interface between the structure and the electrical or instrument component.

- Conduit and Conduit Supports

  The Conduit and Conduit Supports commodity group includes components such as rigid and flexible electrical conduits and fittings. Components evaluated in this group include conduit, and its structural support members, welds, bolting, anchorage and building concrete at anchorage, etc., that comprise the interface between the structure and the electrical, or instrument component. These commodity groups also include the associated supports.

- Electrical Panels, Racks, Cabinets and Other Enclosures

  The Electrical Panels, Racks, Cabinets and Other Enclosures commodity group includes components such as electrical panels, frames and racks, cabinets, and boxes, and enclosures that contain sample stations. Components evaluated in this group also include support structural members, welds, bolting, anchorage and building concrete at anchorage, that comprise the interface between the structure and the electrical or instrument component.

- Equipment Supports and Foundations

  The Equipment Supports and Foundations commodity group includes the equipment supports and foundations within the following structures: the Reactor Buildings, Primary Containment Structures, the Unit 1/2 Diesel Generator Buildings, the Unit 3 Diesel Generator Building, the Intake Pumping Station, the Reinforced Concrete Chimney, the Standby Gas Treatment Building, the Equipment Access Lock, the Vacuum Pipe Building, the Turbine Buildings, the Diesel High Pressure Fire Pump House; the Transformer Yard; the 161 kV Switchyard; and the 500 kV Switchyard. The Condensate Water Storage Tanks Foundations, Nitrogen Storage Tank Foundation and the CAD System Storage Tank Foundations are addressed separately in Sections 2.4.23, 2.4.24 and 2.4.26, respectively. Components evaluated in this group include equipment foundations within the structures, and support structural members, welds, bolting, anchorage and building concrete at anchorage, that comprise the interface between the structure and the mechanical component.

- Hazard Barriers and Elastomers

  Hazard Barriers and Elastomers commodity group includes those hazard barriers not associated with the overall structure, such as a floor or wall. Hazard barriers include penetration seals, hazard barrier doors, fire wraps, fire coatings, fire dampers and other hazard barriers such as missile, radiation, and spray shields. Elastomer components include expansion joint seals (seismic joint seal material, control joint seal material, and seismic separation joint seal material), gaskets at hatches and doors, spent fuel pool gate seals, blowout panel seals, and metal siding gap seals. Hazard Barriers and Elastomers also include roofing assemblies and permanent lead shielding blankets.

- HVAC Duct Supports

  The HVAC Duct Supports commodity group includes the supports and support anchorage for HVAC ducts and associated components. Components evaluated in this group include HVAC ducting and their structural support members, welds, bolting, anchorage and building concrete at anchorage, that comprise the interface between the structure and the HVAC ducts and associated components.

- Miscellaneous Steel

  The Miscellaneous Steel commodity group includes platforms, grating, stairs, ladders, steel curbs, handrails, kick plates, diamond plate type decking, hatches, plugs and manhole covers. This commodity group also includes vents, louvers, and roof scuttles. These steel and other metal components are generally installed throughout BFN structures. Some components are exposed to the outdoor environment. Components evaluated in this group include miscellaneous steel components and their structural support members, welds, bolting, anchorage and building concrete at anchorage, that comprise the interface between the structure and the miscellaneous steel components.

- Penetrations and Sleeves

  The Penetrations and Sleeves commodity group includes the equipment used for mechanical and electrical penetrations. Penetrations and 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. The majority of the system components are penetrations and sleeves that provide physical support to the mechanical or electrical system components passing through the penetration. These penetrations and sleeves and other penetration support equipment are evaluated as structural components. Components evaluated in this group include penetrations and sleeves and their structural support members, welds, bolting, anchorage and building concrete at anchorage, that comprise the interface between the structure and the penetration and sleeves components.

- Pilings

  The Pilings commodity group includes piles that support the following structures: the Equipment Access Lock; the Turbine Buildings; the Radwaste Building; Gate Structure Number 2; Gate Structure Number 3; the Discharge Control Structure; the Diesel High Pressure Fire Pump House; the Transformer Yard; and the RHRSW Tunnel. Piles are used under these structures to transfer foundation loadings to greater depths below grade. The function of the piles is to support superimposed structural loads and to transfer the structural loads to soil or rock of good bearing capacity.

- Pipe Whip Restraints and Jet Impingement Shields

  The Pipe Whip Restraint and Jet Impingement Shields commodity group consists of the restraints relied upon to limit pipe displacement in the event of a high energy pipe break. Components evaluated in this group include structural members, welds, bolting, anchorage, and the building concrete at anchorage that comprises the interface between the structure and the pipe whip restraint or jet impingement shield.

  Pipe whip restraints and jet impingement shields that are designed and installed to protect safety-related equipment from the effects of a HELB, are within the scope of subsequent license renewal. Along with this mitigative option, BFN also employs the preventive option of including nonsafety-related liquid-filled lines with potential leakage or spray spatial interaction within the scope of subsequent license renewal.

- Piping Supports

  The Piping Support commodity group includes the supports and support anchorage for piping and piping components. Components evaluated in this group include support structural members, welds, bolting, anchorage and building concrete at anchorage, that comprise the interface between the structure and the piping and piping component.

- Thermal Insulation

  The Thermal Insulation commodity group consists of insulation and jacketing that are installed on piping and other mechanical components for the purpose of heat conservation, temperature control, and prevention of condensation. Components evaluated in this group include insulation and insulation jacketing.

- Tube Track

  The Tube Track commodity group includes the supports and support anchorage for tube track. Components evaluated in this group include tube track and its structural support members, welds, bolting, anchorage and building concrete at anchorage, that comprise the interface between the structure and the tube track.

Structural commodities components in scope for subsequent license renewal are those components in structures and areas with mechanical or electrical components in scope for subsequent license renewal. Structural commodities components are not in scope for subsequent license renewal were installed in other structures and areas where there are no mechanical or electrical components in scope for subsequent license renewal.

Structural commodities groups are not described in the FSAR. Refer to the “Components Subject to Aging Management Review” tables below for a list of components included in the boundaries of each of the structural commodities groups. Structural commodities are not shown on the subsequent license renewal boundary drawing since these commodities are included where located in structures in scope for subsequent license renewal.

Intended Functions

1. Portions of the structural commodities provide physical support, shelter, and protection for safety-related SSCs. 10 CFR 54.4(a)(1)
2. Portions of the structural commodities provide physical support, shelter, and protection for nonsafety-related SSCs whose failure could prevent satisfactory accomplishment of function(s) identified for 10 CFR 54.4(a)(1). 10 CFR 54.4(a)(2)
3. Portions of the structural commodities provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Anticipated Transient without Scram (10 CFR 50.62). 10 CFR 54.4(a)(3)
4. Portions of the structural commodities provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Environmental Qualification (10 CFR 50.49). 10 CFR 54.4(a)(3)
5. Portions of the structural commodities provide physical support, shelter, and protection for SSCs relied upon 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). 10 CFR 54.4(a)(3)
6. Portions of the structural commodities provide physical support, shelter, and protection for SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for Station Blackout (10 CFR 50.63). 10 CFR 54.4(a)(3)

FSAR References

None

Subsequent License Renewal Boundary Drawings

None

Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-36, Structural Commodities.

Table 2.4-36, Structural Commodities

Component Type	Passive Intended Functions
Cable Trays and Supports	
Building Concrete at Locations of Expansion and Grouted Anchors; Grout Pads for Support Base Plates	Structural Support
Structural Bolting	Structural Support
Support Members; Welds; Bolted Connections; Support Anchorage to Building Structure	Structural Support
Conduit and Conduit Supports	
Building Concrete at Locations of Expansion and Grouted Anchors; Grout Pads for Support Base Plates	Structural Support
Conduit	Structural Support, Shelter and Protection
Steel Components: All Structural Steel	Structural Support
Structural Bolting	Structural Support
Support Members; Welds; Bolted Connections; Support Anchorage to Building Structure	Structural Support
Electrical Panels, Racks, Cabinets, and Other Enclosures	
Building Concrete at Locations of Expansion and Grouted Anchors; Grout Pads for Support Base Plates	Structural Support
Structural Bolting	Structural Support
Support Members; Welds; Bolted Connections; Support Anchorage to Building Structure	Structural Support
Equipment Supports and Foundations	
Building Concrete at Locations of Expansion and Grouted Anchors; Grout Pads for Support Base Plates	Structural Support
Constant And Variable Load Spring Hangers; Guides; Stops	Structural Support
Sliding Surfaces	Structural Support
Structural Bolting	Structural Support
Support Members; Welds; Bolted Connections; Support Anchorage to Building Structure	Structural Support
Vibration Isolation Elements	Structural Support
Hazard Barriers and Elastomers	
Controlled Leakage Door	Fire Barrier, Flood Barrier, HELB Shielding, Pressure Boundary, Shelter and Protection

Table 2.4-36, Structural Commodities (Continued)

Component Type	Passive Intended Functions
Fire Barriers Fire Barrier Penetration Seals Fire Dampers Fireproofing; Fire Barriers Fire Rated Doors Structural Fire Barrier Walls Structural Fire Barriers: Walls, Ceilings And Floors	Fire Barrier, Flood Barrier, Structural Support
Membrane	Shelter and Protection
Moisture Barriers (Caulking, Flashing, Other Sealants)	Flood Barrier, Pressure Boundary, Shelter and Protection
Radiation Protection Blankets	Shielding
Compressible Joints And Seals Seals; Gaskets; Moisture Barriers (Caulking, Flashing, And Other Sealants) Seals; Gaskets; Moisture Barriers (Spent Fuel Pool Gates)	Flood Barrier, Pressure Boundary, Water Retaining Boundary
Steel Components: All Structural Steel	Shelter and Protection, Structural Support
Structural Bolting	Structural Support
HVAC Duct Supports	
Building Concrete at Locations of Expansion and Grouted Anchors; Grout Pads for Support Base Plates	Structural Support
Structural Bolting	Structural Support
Support Members; Welds; Bolted Connections; Support Anchorage to Building Structure	Structural Support
Miscellaneous Steel	
Building Concrete at Locations of Expansion and Grouted Anchors; Grout Pads for Support Base Plates	Structural Support
Equipment Hatch, CRD Hatch Hatches / Plugs Steel Components: All Structural Steel	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support
Structural Bolting	Structural Support
Support Members; Welds; Bolted Connections; Support Anchorage to Building Structure	Structural Support
Penetration and Sleeves	
Building Concrete at Locations of Expansion and Grouted Anchors; Grout Pads for Support Base Plates	Structural Support

Table 2.4-36, Structural Commodities (Continued)

Component Type	Passive Intended Functions
Penetrations; Electrical and I&C Penetrations; Mechanical Penetration Sleeves Steel Components: Penetrations	Flood barrier, Pressure Boundary, Shelter and Protection, Structural Support
Structural Bolting	Structural Support
Support Members; Welds; Bolted Connections; Support Anchorage to Building Structure	Structural Support
Pilings	
Steel Components: Piles	Structural Support
Pipe Whip Restraints and Jet Impingement Shields	
Building Concrete at Locations of Expansion and Grouted Anchors; Grout Pads for Support Base Plates	Structural Support
Pipe Whip Restraints and Jet Impingement Shields	Pipe Whip Restraint, HELB Shielding
Structural Bolting	Structural Support
Support Members; Welds; Bolted Connections; Support Anchorage to Building Structure	Structural Support
Piping Supports	
Building Concrete at Locations of Expansion and Grouted Anchors; Grout Pads for Support Base Plates	Structural Support
Constant and Variable Load Spring Hangers; Guides; Stops	Structural Support
Sliding Surfaces	Structural Support
Structural Bolting High-Strength Structural Bolting	Structural Support
Support Members; Welds; Bolted Connections; Support Anchorage to Building Structure	Structural Support
Thermal Insulation	
Insulation: Metallic Insulation Non-Metallic Insulation	Thermal Insulation
Insulation Jacketing	Thermal Insulation Jacket Integrity
Tube Track	
Building Concrete at Locations of Expansion and Grouted Anchors; Grout Pads for Support Base Plates	Structural Support
Sliding Support Bearings; Sliding Support Surfaces	Structural Support

Table 2.4-36, Structural Commodities (Continued)

Component Type	Passive Intended Functions
Structural Bolting	Structural Support
Support Members; Welds; Bolted Connections; Support Anchorage to Building Structure	Structural Support

The aging management review results for these components are provided in Table 3.5.2-36, Structural Commodities - Summary of Aging Management Evaluation.

2.4.37 Isolation Valve Pits

Description

The Isolation Valve Pits provide structural support and shelter/protection for the Hardened Containment Venting System. These Class II (non-safety-related) structures are attached to the south wall of the Reactor Building.

The Isolation Valve Pits house a portion of the Hardened Containment Venting System. The Hardened Containment Venting System is credited in the Fire Probabilistic Risk Assessment (PRA) model for decay heat removal when all other decay heat removal functions are lost. The portion of the Hardened Containment Venting System upstream of and including the outboard isolation valve also serves a Primary Containment System function.

Components not included in the evaluation boundary of the Isolation Valve Pits are Cable Trays and Supports; Conduit and Conduit Supports; Electrical Panels, Racks, Cabinets, and Other Enclosures; Equipment Supports and Foundations; Hazard Barriers and Elastomers; HVAC Duct Supports; Miscellaneous Steel; Penetration and Sleeves; Pilings; Pipe Whip Restraints andJet Impingement Shields; Piping Supports; Thermal Insulation; and Tube Track. These components are evaluated as Structural Commodities.

The Isolation Valve Pits are not described in the FSAR. The structure is shown in the subsequent license renewal boundary drawings listed below.

Intended Functions

1. Provide structural support and shelter/protection for components of the Hardened Containment Venting System. 10 CFR 54.4(a)(3)

FSAR References

None

Subsequent License Renewal Boundary Drawings

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Components Subject to AMR

The component types that require aging management review are indicated in the below Table 2.4-37, Isolation Valve Pits.

Table 2.4-37, Isolation Valve Pits

Component Type	Passive Intended Functions
Concrete (accessible areas): Above Grade Exterior Concrete (accessible areas): All Concrete (accessible areas): Exterior Above And Below Grade; Foundation Concrete (accessible areas): Interior Concrete (inaccessible areas): All Concrete (inaccessible areas): Below Grade Exterior; Foundation Concrete (inaccessible areas): Exterior Above And Below Grade; Foundation Concrete (inaccessible areas): Foundation Concrete: Above Grade Exterior Concrete: All Concrete: Interior	Shelter and Protection, Structural Support
Steel components: All Structural Steel	Structural Support
Structural Bolting	Structural Support

The aging management review results for these components are provided in Table 3.5.2-37, Isolation Valve Pits - Summary of Aging Management Evaluation.

2.5 SCOPING AND SCREENING RESULTS: ELECTRICAL

The determination of electrical systems that fall within the scope of license renewal is made through the application of the process described in Section 2.1. The results of the electrical systems scoping review are contained in Section 2.2.

Subsection 2.1.6.1 provides the screening methodology for determining which electrical components and commodity groups within the scope of 10 CFR 54.4 meet the requirements contained in 10 CFR 54.21(a)(1). The electrical commodity groups that meet those screening requirements are identified in this section. These identified electrical commodity groups consequently require an aging management review.

As described in Subsection 2.1.6.1, the screening was performed on a commodity group basis for the in scope electrical and I&C systems as well as the electrical and I&C component types associated with in scope mechanical systems listed in Table 2.2-1.

Components which support or interface with electrical and I&C components, for example, cable trays, conduits, instrument racks, panels and enclosures, are assessed as part of the Structural Commodities in Section 2.4.36.

2.5.1 Electrical and I&C Systems

The results of the electrical and I&C systems scoping review are contained in Section 2.2. Additional system details are included in the FSAR Section 2.5.5, Chapter 5, Chapter 7 and Chapter 8. In addition to the electrical and I&C systems and components, certain switchyard components are credited to restore offsite power following an SBO. The boundary for offsite power restoration following an SBO is shown in Figures 2-1, 2-2, and 2-3. The Figures also show the Alternate AC power source for the SBO coping period.

2.5.2 Electrical and I&C Commodities

2.5.2.1 Identification of Electrical and I&C Commodities

The first step of the screening process for electrical and I&C commodities is to use plant documentation to identify the electrical and I&C components and commodities within the electrical, I&C, and mechanical systems. This identification is based on review of plant design documentation, drawings, and the Maximo equipment database, as well as review of the parallel mechanical and civil screening efforts. The electrical and I&C components and commodities identified at BFN are listed below. This list includes electrical and I&C components and commodities identified in NUREG-2192, Table 2.1-6, as applicable at BFN.

Electrical and I&C Components and Commodities for In-Scope Systems:

- Alarm Units
- Analyzers
- Annunciators
- Batteries
- Cable Connections (Metallic Parts)
- Cable Tie Wraps
- Chargers

- Circuit Breakers
- Communication Equipment
- Computers
- Controllers
- Converters
- Electric Heaters
- Electrical Controls and Panel Internal Assemblies
- Electrical Insulation for Electrical Cables and Connections
- Electrical Penetrations
- Elements, Sensors, Thermocouples, Transducers
- Fuses
- Fuse Holders (part of active equipment)
- Fuse Holders (not part of active equipment)
- Generators, Motors
- Heat Trace
- High Voltage Electrical Insulators
- Indicators
- Inverters
- Isolators
- Light Bulbs
- Metal Enclosed Bus
- Meters
- Modifier (analog/digital input/output modules, signal converters, pre-amps, etc.)
- Power Supplies
- Radiation Monitors
- Recorders
- Regulators
- Relays
- Signal Conditioners
- Solenoid Operators
- Solid State Devices
- Splices
- Switches
- Switchgear, Load Centers, Motor Control Centers, Distribution Panels
- Switchyard Bus and Connections
- Terminal Blocks
- Transformers
- Transmission Conductors
- Transmission Connectors
- Transmitters
- Uninsulated Ground Conductors

2.5.2.2 Application of Screening Criterion 10 CFR 54.21(a)(1)(i) to the Electrical and I&C Components and Commodities

Following the identification of the electrical and I&C components and 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 and I&C commodities were determined to meet the screening criteria of 10 CFR 54.21(a)(1)(i):

- Cable Connections (Metallic Parts)
- Cable Tie Wraps
- Electrical Insulation for Electrical Cables and Connections
- Electrical Penetrations
- Fuse Holders (not part of active equipment)
- High Voltage Electrical Insulators
- Metal Enclosed Bus
- Switchyard Bus and Connections, Transmission Conductors and Transmission Connectors
- Uninsulated Ground Conductors

2.5.2.3 Elimination of Electrical and I&C Commodity Groups With No Subsequent License Renewal Intended Function

The following electrical and I&C commodities were determined to not have a subsequent license renewal intended function:

- Cable Tie Wraps

  Tie wraps are used in cable installations as cable ties. Cable ties hold groups of cables together for restraint and ease of maintenance. Cable ties are used to bundle wires and cables together to keep the wire and cable runs neat and orderly. Cable ties are used to restrain wires and cables within raceways to facilitate cable installation. There are no current license basis requirements for BFN that cable tie wraps remain functional during and following design basis events. Cable ties are not credited for maintaining cable ampacity, ensuring maintenance of cable minimum bending radius, or maintaining cables within vertical raceways at BFN. The seismic qualification of cable trays does not credit the use of cable ties. Cable tie wraps are not credited in the BFN 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 therefore, are not subject to aging management review.

- Uninsulated Ground Conductors

  The uninsulated ground conductor commodity 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 therefore, are not subject to aging management review.

2.5.2.4 Application of Screening Criteria 10 CFR 54.21 (a)(1)(ii) to Electrical and I&C Commodities

The 10 CFR 54.21(a)(1)(ii) screening criterion was applied to the specific commodities that remained following application of the 10 CFR 54.21(a)(1)(i) criterion. 10 CFR 54.21(a)(1)(ii) allows the exclusion of those commodities that are subject to replacement based on a qualified life or specified time period. The only electrical and I&C commodities identified for exclusion by the criteria of 10 CFR 54.21(a)(1)(ii) are electrical and I&C commodities included in the EQ of Electric Equipment program (B.3.1.3). This is because electrical and I&C 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 commodities within the EQ Program are subject to aging management review in accordance with the screening criteria of 10 CFR 54.21(a)(1)(ii). See Section 4.4 for the TLAA evaluation of the EQ of Electric Equipment Aging Management Program. The remaining commodities, all or part of which are not in the EQ Program, require aging management review and are discussed below.

2.5.2.5 Electrical and I&C Commodities Subject to Aging Management Review

The electrical and I&C commodities subject to aging management review are summarized in Table 2.5.2-1, along with the associated intended functions. These electrical commodities are discussed below.

2.5.2.5.1 Cable Connections (Metallic Parts)

The Cable Connectors (Metallic Parts) commodity includes metallic portions of cable connections that are not included in the EQ Program. The metallic connections evaluated include splices, threaded connectors, compression type termination lugs, and terminal blocks. Therefore, Cable Connections (Metallic Parts) meet the screening criterion of 10 CFR 54.21(a)(1)(ii) and are subject to aging management review.

2.5.2.5.2 Electrical Insulation for Electrical Cables and Connections

The insulated cables and connections commodities are separated for aging management review into subcategories based on their treatment in NUREG-2191:

- Electrical Insulation for Electrical Cables and Connections, which includes:
    - Electrical Penetration Pigtails
    - Splices
    - Insulating Portion of Terminal Blocks
    - Insulating Portion of Fuse Holders (not part of active equipment).
- Electrical Insulation for Electrical Cables and Connections Used in Instrumentation Circuits
- Electrical Insulation for Inaccessible Medium Voltage Power Cables
- Electrical Insulation for Inaccessible Instrumentation and Control Cables
- Electrical Insulation for Inaccessible Low Voltage Power Cables

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.

Insulated cables and connections inside the enclosure of an active device (e.g., motor leads and connections, cables and connections internal to relays, chargers, switchgear, transformers, power supplies) are maintained along with the other subcomponents inside the enclosure and are not subject to an aging management review.

2.5.2.5.3 Electrical Penetrations

A portion of the electrical penetrations at BFN are environmentally qualified. These electrical penetrations are evaluated as a TLAA, Section 2.5.2.4, and are managed by the EQ of Electrical Equipment program (B.3.1.3). For the remainder of the electrical penetrations, the electrical penetration pigtails and associated connections that could potentially be exposed to an adverse localized environment is included in the evaluation for Electrical Insulation for Electrical Cables and Connections, Section 2.5.2.5.2. The shelter, protection and pressure boundary intended functions of electrical penetrations are included in the evaluation for Structural Commodities (Section 2.4.36).

2.5.2.5.4 Fuse Holders (not part of active equipment)

The Fuse Holders commodity includes fuse holders that are not part of a larger active assembly and are not included in the EQ program. Both the metallic and non-metallic portions of fuse holders that are not part of a larger active assembly and are not included in the EQ program meet the screening criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an aging management review.

2.5.2.5.5 High Voltage Electrical Insulators

The High Voltage Electrical Insulators' intended function is to insulate (electrical) for Switchyard Bus, Transmission Conductors, and switchyard active components that are part of the circuits that supply power from the transmission system to plant buses, including connecting the alternate ac source in the event of an SBO. These circuits provide power to in scope subsequent license renewal components used for coping during and recovery from an SBO event and used for achieving and maintaining safe and stable conditions in the event of a fire, when offsite power is credited. High Voltage Electrical Insulators are not included in the EQ program. Therefore, High Voltage Electrical Insulators meet the screening criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an aging management review.

2.5.2.5.6 Metal Enclosed Bus

The metal enclosed buses at BFN include the sections of isolated phase bus that connect the USSTs and the Main Generator Breaker to the Main Transformers, the sections of non-segregated phase bus that connect the CSSTs to the 4 kV Unit Start Boards, and the sections of non-segregated phase bus that connect the USSTs to the 4 kV Unit Boards and the 4 kV Recirculation Pump Boards. The Metal Enclosed Buses are the circuits that supply power from the Main Transformers to plant buses, including connecting the alternate ac source in the event of an SBO. These portions of the power distribution system are in scope for subsequent license renewal. The metal enclosed buses are not in the EQ Program. Therefore, metal enclosed buses meet the screening criterion of 10 CFR 54.21(a)(1)(ii) and are subject to aging management review.

2.5.2.5.7 Switchyard Bus and Connections, Transmission Conductors and Transmission Connectors

The Switchyard Bus and Connections are part of the switchyard circuits that supply power from the transmission system to plant buses, including connecting the alternate AC source in the event of an SBO. These circuits provide power to in scope subsequent license renewal components used for coping during and recovery from an SBO and used for achieving and maintaining safe and stable conditions in the event of a fire, when offsite power is credited. The

Switchyard Bus and Connections are not included in the EQ program. Therefore, Switchyard Bus and Connections meet the screening criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an aging management review.

The Transmission Conductors and the Transmission Connectors are part of the switchyard circuits that supply power from the transmission system to plant buses including connecting the alternate ac source in the event of an SBO. These circuits provide power to in scope subsequent license renewal components used for coping during and recovery from an SBO and used for achieving and maintaining safe and stable conditions in the event of a fire, when offsite power is credited. The Transmission Conductors and the Transmission Connectors are not included in the EQ program. Therefore, the Transmission Conductors and the Transmission Connectors meet the screening criterion of 10 CFR 54.21(a)(1)(ii) and are subject to an aging management review.

Table 2.5.2-1, Electrical and I&C Commodities Subject to Aging Management Review

Commodity	Passive Intended Functions
Cable Connections (Metallic Parts)	Electrical Continuity
Electrical Insulation for Electrical Cables and Connections	Insulate (Electrical)
Fuse Holders (not part of active equipment)	Insulate (Electrical), Electrical Continuity
High Voltage Electrical Insulators	Insulate (Electrical)
Metal Enclosed Bus	Electrical Continuity, Insulate (Electrical), Shelter, Protection
Switchyard Bus and Connections	Electrical Continuity
Transmission Conductors	Electrical Continuity
Transmission Connectors	Electrical Continuity

The aging management review results for these commodities are provided in Table 3.6.2-1, Electrical and I&C Commodities – Summary of Aging Management Evaluation.

3.0 AGING MANAGEMENT REVIEW RESULTS

This section provides the results of the aging management review for those structures and components identified in Section 2.0 as being subject to aging management review. Descriptions of the service environments that were used in the aging management review to determine aging effects requiring management are included in Table 3.0-1, Browns Ferry Nuclear Plant Service Environments. The environments used in the aging management reviews are listed in the BFN Aging Management Review (AMR) Environment column. The third column identifies one or more of the NUREG-2191 environments that were used when comparing the Browns Ferry Nuclear Plant (BFN) AMR results to the NUREG-2191 results.

Most of the 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-2192, 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 and Reactor Core Isolation Cooling System 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-2192, 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 Pressure Vessel Instrumentation System, it would be table 3.1.2-2. For the Containment Atmosphere Dilution System, within the Engineered Safety Features (ESF) and Reactor Core Isolation Cooling (RCIC) System subsection, this table would be 3.2.2-1. For the next system within the ESF and RCIC System 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

NUREG-2191 contains the generic evaluation of existing plant programs. It documents the technical basis for determining where existing programs are adequate without modification, and where existing programs should be augmented for the second extended period of operation. The evaluation results documented in NUREG-2191 indicate that many of the existing programs are adequate to manage the aging effects for particular structures or components, within the scope of license renewal, without change. NUREG-2191 also contains recommendations on specific areas for which existing programs should be enhanced for license renewal. In order to take full advantage of NUREG-2191, a comparison between the BFN AMR results and the tables of NUREG-2191 has been performed. The results of that comparison are provided in Table 1 and Table 2.

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 first three columns, “New, Modified, Deleted, Edited Item", "ID", and "Type", have been replaced by an "Item Number" column and the "GALLSLR 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-2192 assumptions, if applicable
- A discussion of how the line is consistent with the corresponding line item in NUREG2192, when that may not be intuitively obvious
- A discussion of how the item is different than the corresponding line item in NUREG-2192 when it may appear to be consistent (e.g., when there is exception taken to an aging management program that is listed in NUREG-2192), if applicable

The format of Table 1 provides the reviewer with a means of aligning a specific Table 1 row with the corresponding NUREG-2192 table row, thereby allowing for the ease of checking consistency.

Table 2

Table 2 provides the detailed results of the 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 in-scope systems, structures, and commodities within each Chapter 3 Section grouping. For example, for BFN, the Engineered Safety Features and Reactor Core Isolation Cooling Systems Group contains tables specific to the Containment System, Standby Gas Treatment System, Reactor Core Isolation Cooling System, High Pressure Coolant Injection System, Residual Heat Removal System, Core Spray System, and Containment Atmosphere Dilution 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
- NUREG-2192 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 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 and description of these environments is provided in Table 3.0-1.

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 left blank. Thus, a reviewer can readily identify the correlation between the plant-specific tables and the NUREG-2191 tables.

NUREG-2192 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 left blank. The NUREG-2192 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 BFN 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.

<u>Table Usage</u>

Table 1

The reviewer may evaluate each row in Table 1 by moving from left to right across the table. Since the Component, Aging Effect, Aging Management Programs and Further Evaluation Recommended information is taken directly from NUREG-2192, no further analysis of those columns is required. Summary plant-specific information is provided within the Discussion column to demonstrate how the BFN aging management review evaluations and aging management programs align with NUREG-2192. 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.

Table 2

Table 2 contains all of the Aging Management Review information for the plant, including whether or not it aligns with NUREG-2191 recommendations. For a given row within the table, the reviewer is able to see the intended function, material, environment, aging effect requiring management and aging management program combination for a particular component type within a system. In addition, if there is a correlation between the combination in Table 2 and a combination in NUREG-2191, this is 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 is blank, no corresponding combination in NUREG-2191 was found. As the reviewer continues across the table from left to right, within a given row, the next column is labeled NUREG-2192 Table 1 Item. If there is a reference number in this column, the reviewer is able to use that reference number to locate the corresponding row in Table 1 and see how the aging management program for this particular combination aligns with NUREG-2191.

Table 2 provides the reviewer with a means to navigate from the components subject to AMR in SLRA Section 2 all the way through the evaluation of the programs that will be used to manage the effects of aging of those components.

A listing of the acronyms used in this section is provided in Section 1.6.

<u>Cumulative Fatigue Damage and Time Limited Aging Analyses in Table 2</u>

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 60 years of plant operation. Additionally, there are other TLAAs that affect identified aging effects for specific components. 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 where the component for which a TLAA has been identified. See SLRA Section 4 for details regarding the BFN design bases, TLAAs identified, and TLAA evaluations for the subsequent period of extended operation.

Table 3.0-1, Browns Ferry Nuclear Plant Service Environments

BFN AMR Environment	Description	Corresponding NUREG 2191 Environments
10 CFR 50.49 EQ Environments	This environment is used for 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, in which the requirements of 10 CFR 50.49 would be applicable.	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	An adverse localized environment (ALE) is an environment limited to the immediate vicinity of a component that is hostile to the component material, thereby leading to potential aging effects. Electrical insulation used for electrical cables can be subjected to an adverse localized environment. Adverse localized environment can be due to any of the following: (1) exposure to significant moisture, or (2) heat, radiation, or moisture and are represented by specific GALL-SLR AMR items.	Adverse localized environment
Adverse localized environment caused by significant moisture	This environment is the same as the Adverse Localized Environment, except that it is caused by the presence of significant moisture.	Adverse localized environment caused by significant moisture
Air	Any indoor or outdoor air environment where the cited aging effects could occur regardless of the particular air environment (e.g., air-indoor uncontrolled, air-outdoor). For example: (a) hardening or loss of strength of elastomeric components occurs in many different air environments depending upon environmental parameters such as temperature, ozone, ultraviolet light, and radiation; (b) loss of preload for closure bolting can occur in a variety of air environments. The term “air” was incorporated to allow the aging management review line items to be more succinct in regard to citing environments. This term does not encompass the air environment downstream of instrument air dryers, air-dry, or the underground environment. The potential for leakage from bolted connections (e.g., flanges, packing) impacting in-scope components exists when citing the air environment.	Air
Air-dry	Air that has been treated to reduce its dew point well below the system operating temperature and treated to control lubricant content, particulate matter, and other corrosive contaminants. Use of this term is only associated with internal air environments located downstream of the compressed air system air dryers.	Air-dry

Table 3.0-1, Browns Ferry Nuclear Plant Service Environments (Continued)

BFN AMR Environment	Description	Corresponding NUREG 2191 Environments
Air-indoor controlled Air-indoor	An environment where the specified internal or external surface of the component or structure is exposed to a humidity-controlled (i.e., air conditioned) environment. For electrical components and structures, the controlled environment must be sufficient to show that the electrical component(s) or structure(s) are not subjected to the cited aging effect(s) (e.g., reduced insulation resistance). The potential for leakage from bolted connections (e.g., flanges, packing) impacting in-scope components exists when citing the air-indoor controlled environment.	Air-indoor controlled
Air-indoor uncontrolled Air-indoor	Air-indoor uncontrolled is associated with systems with temperatures higher than the dew point (i.e., condensation can occur, but only rarely; equipment surfaces are normally dry). The potential for leakage from bolted connections (e.g., flanges, packing) impacting in-scope components exists when citing the air-indoor uncontrolled environment.	Air-indoor uncontrolled
Air-outdoor	The outdoor environment consists of moist air, cooling tower plumes (which might contain chemical additives), industrial pollutants (e.g., fly ash, soot), ambient temperatures and humidity, and exposure to weather events, including precipitation and wind. The outdoor air environment also potentially includes component contamination due to animal infestation including by-products or excrement containing uric acid, ammonia, phosphates, or other compounds. The outdoor air environment can also result in submergence of components (particularly when they are in vaults) due to the potential for water to accumulate or due to external or internal buildup of condensation.	Air-outdoor
Closed-cycle cooling water Closed-cycle cooling water (Treated)	A subset of treated water that is subject to the closed treated water systems program. Systems are closed in that the rate of recirculation is much higher than the rate of makeup water addition. Examples include the closed portions of Heating, Ventilation, and Air Conditioning (HVAC) systems and diesel generator cooling water systems.	Closed-cycle cooling water
Closed-cycle cooling water >60°C (>140°F)	The Closed Cycle Cooling Water >60°C (>140°F) environment is the same as the Closed Cycle Cooling Water environment, except the Closed Cycle Cooling Water >60°C (>140°F) environment is used for components with an operating temperature >60°C (>140°F0)that are constructed of stainless steel. Closed-cycle cooling water systems above 60°C (>140°F) exceed the threshold for Stainless Steel (SS) Stress Corrosion Cracking (SCC).	Closed-cycle cooling water Closed-cycle cooling water >60°C (>140°F)
Concrete	This environment consists of components that sit on concrete or are embedded in concrete.	Concrete

Table 3.0-1, Browns Ferry Nuclear Plant Service Environments (Continued)

BFN AMR Environment	Description	Corresponding NUREG 2191 Environments
Condensation	Condensation on the surfaces of systems at temperatures below the dew point facilitates loss of material in steel caused by general, pitting, and crevice corrosion. It also facilitates cracking in those materials susceptible to stress corrosion cracking due to the potential for internal or external surface contamination. The former term “moist air” is subsumed by the usage of the term “condensation.” Moisture in the air can result in loss of material or cracking due to hygroscopic surface contaminants. Condensation can form between thermal insulation and a component when air intrusion occurs through minor gaps in the insulation and the operating temperature of the component is below the dew point of the penetrating air.	Condensation
Diesel exhaust	This environment consists of gases, fluids, and particulates present in diesel engine exhaust.	Diesel exhaust
Embedded / Encased	Polyurethane foam is attached to the Drywell steel liner on one side and separated from the reactor building concrete by fiberglass laminate forms on the other side such that the polyurethane foam is embedded/encased.	Not applicable
Fuel oil	Diesel oil, Number 2 oil, or other liquid hydrocarbons used to fuel diesel engines. Fuel oil used for combustion engines may be contaminated with water, which may promote additional aging effects.	Fuel oil
Gas	Internal gas environments include inert or nonreactive gases. This generic term is used where aging effects are not expected to degrade the ability of the structure or component to perform its intended function for the subsequent period of extended operation. The term “gas” is not meant to comprehensively include all gases in the fire suppression system. The GALL-SLR Report AMP XI.M26, “Fire Protection,” is used for the periodic inspection and testing of the halon/carbon dioxide fire suppression system.	Gas
Groundwater/soil	Groundwater is subsurface water that can be detected in wells, tunnels, or drainage galleries, or that flows naturally to the earth's surface via seeps or springs. Soil is a mixture of organic and inorganic materials produced by the weathering of rock and clay minerals or the decomposition of vegetation. Voids containing air and moisture can occupy 30-60% of the soil volume. Concrete subjected to a groundwater/soil environment can be vulnerable to an increase in porosity and permeability, cracking, loss of material (spalling, scaling), or aggressive chemical attack. Other materials with prolonged exposures to groundwater or moist soils are subject to the same aging effects as those systems and components exposed to raw water.	Groundwater/soil

Table 3.0-1, Browns Ferry Nuclear Plant Service Environments (Continued)

BFN AMR Environment	Description	Corresponding NUREG 2191 Environments
Lubricating oil	Lubricating oils are low-to-medium viscosity hydrocarbons that can contain contaminants and/or moisture. This usage also functionally encompasses hydraulic oil (nonwater based). These oils are used for bearing, gear, and engine lubrication. Piping and piping components, whether copper, SS, or steel, when exposed to lubricating oil with some water, will have limited susceptibility to aging degradation due to general or localized corrosion. Lubricating oil (waste oil) and lubricating oil are two different environments. Lubricating oil (waste oil) is oil that has been collected as it leaks from a component (e.g., reactor coolant pumps) and as such, contains potential contaminants such as water and dirt. Lubricating oil is unlikely to contain contaminants due to the testing of the oil and corrective actions when contaminants are detected. As a result, one-time inspections for components exposed to these environments are treated as two separate populations.	Lubricating oil
Raw water	Raw water is water that has not been demineralized or treated to any significant extent. Raw water may be rough filtered to remove large particles and may contain biocide and inhibitor additives for control of micro- and macro-organisms.	Raw water
Raw water (potable)	Raw water (potable) is water that has been demineralized, filtered, or otherwise treated, but is not maintained by a chemistry program.	Raw water
Reactor coolant	Reactor coolant is treated water in the reactor coolant system and connected systems at or near full operating temperature, including steam associated with BWRs.	Reactor coolant
Reactor coolant >250°C (>482°F)	Reactor coolant is treated water in the RCS and connected systems and is always assumed to be >482 °F (>250 °C). This applies to thermal embrittlement of Cast Austenitic Stainless Steel.	Reactor coolant >250°C (>482°F)
Reactor coolant and neutron flux	The reactor core environment that will result in a neutron fluence exceeding 1017 n/cm^2 (E >1 MeV) at the end of the license renewal term.	Reactor coolant and neutron flux
Sodium pentaborate solution	Treated water that contains sodium pentaborate, used in the Standby Liquid Control System.	Sodium pentaborate solution
Soil	Soil is a mixture of inorganic materials produced by the weathering of rock and clay minerals, and organic material produced by the decomposition of vegetation. Voids containing air and moisture occupy 30-60% of the soil volume. Properties of soil that can affect degradation kinetics include moisture content, pH, ion exchange capacity, density, and hydraulic conductivity. External environments included in the soil category consist of components at the air/soil interface, buried in the soil, or exposed to groundwater in the soil.	Soil
Steam	The steam environment is managed by the BWR water chemistry program. Defining the temperature of the steam is not considered necessary for analysis.	Steam

Table 3.0-1, Browns Ferry Nuclear Plant Service Environments (Continued)

BFN AMR Environment	Description	Corresponding NUREG 2191 Environments
System temperature up to 288°C (550°F)	This environment consists of a metal temperature of BWR components < 288°C (550°F).	System temperature up to 288°C (550°F)
Treated water	Treated water is water whose chemistry has been altered and is maintained (as evidenced by testing) in a state which differs from naturally-occurring sources so as to meet a desired set of chemical specifications. Treated water generally falls into one of two categories. The first category is based on demineralized water and generally contains minimal amounts of any additions. This water is generally characterized by high purity, low conductivity, and very low oxygen content. This category of treated water is generally used as BWR. The second category may be but need not be based on demineralized water. It contains corrosion inhibitors and also may contain biocides or other additives. This water will generally be comparatively higher in conductivity and oxygen content than the first category of treated water. This category of treated water is generally used in HVAC systems, auxiliary boilers, and diesel engine cooling systems. Closed-cycle cooling water is a subset of this category of treated water.	Treated water
Treated water >60°C (>140°F)	Treated water above the SCC temperature threshold for SS. Treated water above the 60°C (140°F) is the same as the Treated water environment, except the >60°C (>140°F) environment is used for systems operating at temperatures >60°C (>140°F) that are constructed of stainless steel. For materials other than stainless steel, the Treated Water environment is used.	Treated water Treated water >60°C (>140°F)
Treated water >93°C (>200°F)	Treated water above the SCC temperature threshold for SS. The Treated Water >93°C (>200°) environment is the same as the Treated Water environment, except the Treated Water >93°C (>200°F) environment is to be selected for Reactor Water Cleanup (RWCU) System, piping and piping components outboard of the second containment isolation valves with a diameter ≥4 inches nominal pipe size (NPS) and for Reactor Coolant Pressure Boundary Class 1 piping, piping components greater than or equal to 4 NPS.	Treated water Treated water >60°C (>140°F)
Treated water >250°C (>482°F)	Treated water above the thermal embrittlement threshold for Cast Austenitic Stainless Steel (CASS) The Treated Water >250°C (>482°F) environment is the same as the Treated Water environment, except the Treated Water >250°C (>482°F) environment is to be selected for components with an operating temperature >250°C (>482°F) that are constructed of CASS.	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

Table 3.0-1, Browns Ferry Nuclear Plant Service Environments (Continued)

BFN AMR Environment	Description	Corresponding NUREG 2191 Environments
Waste water	Radioactive, potentially radioactive or nonradioactive waters that are collected from equipment and floor drains. Waste waters may contain contaminants, including oil and boric acid, depending on location, as well as originally treated water that is not monitored by a chemistry program.	Waste water
Water-flowing	Water that is refreshed; thus, it has a greater impact on leaching and can include rainwater, raw water, groundwater, or water flowing under a foundation.	Water-flowing
Water-standing	Water that is stagnant and unrefreshed, thus possibly resulting in increased ionic strength up to saturation.	Water-standing

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 (2.3.1.1)
- Reactor Vessel Internals (2.3.1.2)
- Reactor Vessel Vents and Drains System (2.3.1.3)
- Reactor Recirculation System (2.3.1.4)
- Fuel Assemblies (2.3.1.5)

3.1.2 Results

The following tables summarize the results of the aging management review for Reactor Vessel, Internals, and Reactor Coolant System.

- Table 3.1.2-1 Reactor Vessel - Summary of Aging Management Evaluation
- Table 3.1.2-2 Reactor Vessel Internals - Summary of Aging Management Evaluation
- Table 3.1.2-3 Reactor Vessel Vents and Drains System - Summary of Aging Management Evaluation
- Table 3.1.2-4 Reactor Recirculation System - Summary of Aging Management Evaluation
- Table 3.1.2-5 Fuel Assemblies - Summary of Aging Management Evaluation

3.1.2.1 Materials, Environments, Aging Effects Requiring Management and Aging Management Programs

3.1.2.1.1 Reactor Vessel

Materials

The materials of construction for the Reactor Vessel components are:

- Carbon or Low Alloy Steel with Stainless Steel Cladding
- Carbon or Low Alloy Steel with Nickel Alloy Cladding
- Nickel Alloy
- Stainless Steel
- Steel
- Steel Bolting
- High Strength Steel Bolting

Environments

The Reactor Vessel components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Reactor Coolant

- Reactor Coolant and Neutron Flux
- Condensation
- Treated water >60°C [>140°F]

Aging Effects Requiring Management

The following aging effects associated with the Reactor Vessel components require management:

- Cracking
- Cumulative fatigue damage
- Loss of fracture toughness
- Loss of material
- Long-term loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Vessel components:

- Neutron Fluence Monitoring (B.3.1.2)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- Water Chemistry (B.2.1.2)
- Reactor Head Closure Stud Bolting (B.2.1.3)
- BWR Stress Corrosion Cracking (B.2.1.5)
- BWR Penetrations (B.2.1.6)
- BWR Vessel Internals (B.2.1.7)
- Flow-Accelerated Corrosion (B.2.1.9)
- Bolting Integrity (B.2.1.10)
- Reactor Vessel Material Surveillance (B.2.1.19)
- One-Time Inspection (B.2.1.20)
- ASME Code Class 1 Small-Bore Piping (B.2.1.22)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)

3.1.2.1.2 Reactor Vessel Internals

Materials

The materials of construction for the Reactor Vessel Internals components are:

- Nickel Alloy
- Stainless Steel
- Stainless Steel bolting
- Cast Austenitic Stainless Steel (CASS)
- Steel

Environments

The Reactor Vessel Internals components are exposed to the following environments:

- Reactor Coolant
- Reactor Coolant and Neutron Flux
- Air - Indoor Uncontrolled

Aging Effects Requiring Management

The following aging effects associated with the Reactor Vessel Internals components require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Loss of fracture toughness
- Loss of preload
- Long-Term loss of material

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Vessel Internals components:

- Water Chemistry (B.2.1.2)
- BWR Vessel ID Attachment Welds (B.2.1.4)
- BWR Vessel Internals (B.2.1.7)
- One-Time Inspection (B.2.1.20)

3.1.2.1.3 Reactor Vessel Vents and Drains System

Materials

The materials of construction for the Reactor Vessel Vents and Drains System components are:

- Carbon and Low Alloy Steel
- High-Strength Steel
- Stainless Steel
- Stainless Steel - CASS

Environments

The Reactor Vessel Vents and Drains System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the Reactor Vessel Vents and Drains System components require management:

- Cracking
- Cumulative fatigue damage
- Loss of fracture toughness
- Loss of material
- Loss of preload
- Long-term loss of material

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Vessel Vents and Drains System components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- Water Chemistry (B.2.1.2)
- BWR Stress Corrosion Cracking (B.2.1.5)
- Flow-Accelerated Corrosion (B.2.1.8)
- Bolting Integrity (B.2.1.10)
- One-Time Inspection (B.2.1.20)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)

3.1.2.1.4 Reactor Recirculation System

Materials

The materials of construction for the Reactor Recirculation System components are:

- Steel
- Carbon and Low Alloy Steel
- Cast Austenitic Stainless Steel (CASS)
- Copper Alloy with 15% Zinc or Less
- Copper Alloy with Greater Than 15% Zinc
- Glass
- High Strength Steel Bolting
- Stainless Steel
- Steel Bolting

Environments

The Reactor Recirculation System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air, condensation
- Closed-Cycle Cooling WaterLubricating Oil
- Raw Water

- Treated Water
- Treated Water > 60°C (>140°F)
- Treated Water > 93°C (>200°F)
- Treated Water > 250°C (>482°F)

Aging Effects Requiring Management

The following aging effects associated with the Reactor Recirculation System components require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of fracture toughness
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Recirculation System components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- Water Chemistry (B.2.1.2)
- BWR Stress Corrosion Cracking (B.2.1.5)
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B.2.1.8)
- Flow-Accelerated Corrosion (B.2.1.9)
- Bolting Integrity (B.2.1.8)
- Open-Cycle Cooling Water System (B.2.1.11)
- Closed Treated Water Systems (B.2.1.12)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- ASME Code Class 1 Small-Bore Piping (B.2.1.22)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Lubricating Oil Analysis (B.2.1.25)

3.1.2.1.5 Fuel Assemblies

Materials

The materials of construction for the Fuel Assemblies components are:

- Not Applicable (Fuel Assemblies are short-lived components)

Environments

The Fuel Assemblies components are exposed to the following environments:

- Not Applicable

Aging Effects Requiring Management

The following aging effects associated with the Fuel Assemblies components require management:

- None

Aging Management Programs

The following aging management programs manage the aging effects for the Fuel Assemblies components:

- None

3.1.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL-Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the license renewal application. For the Reactor Vessel, Internals, and Reactor Coolant System, those programs are addressed in the following subsections.

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). This TLAA is 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.

Table 3.1.1 Item Number 3.1-1, 001: This item evaluates steel reactor vessel closure flange assembly components exposed to air-indoor uncontrolled for cumulative fatigue damage due to fatigue and cyclic loading. Cumulative fatigue damage of steel reactor vessel closure flange assembly components is evaluated and dispositioned as a TLAA for the Reactor Vessel as discussed in Section 4.3.

Table 3.1.1 Item Number 3.1-1, 003: This item evaluates stainless steel and nickel alloy reactor vessel internal components exposed to reactor coolant with neutron flux for cumulative fatigue damage due to fatigue and cyclic loading. Cumulative fatigue damage of stainless steel and nickel alloy reactor vessel internal components is evaluated and dispositioned as a TLAA for the Reactor Vessel Internals System as discussed in Section 4.3.

Table 3.1.1 Item Number 3.1-1, 004: This item evaluates steel reactor vessel support skirt, and attachment welds for cumulative fatigue damage due to fatigue and cyclic loading. Cumulative fatigue damage of carbon steel reactor vessel external attachments, support skirt, and welds is evaluated and dispositioned as a TLAA for the Reactor Vessel as discussed in Section 4.3.

Table 3.1.1 Item Number 3.1-1, 006: This item evaluates steel (with or without nickel alloy or stainless steel cladding), stainless steel, and nickel alloy reactor coolant pressure boundary components including piping, piping components, and other reactor coolant pressure boundary components exposed to reactor coolant for cumulative fatigue damage due to fatigue and cyclic loading. Cumulative fatigue damage of carbon steel and stainless steel Class 1 piping, piping components is evaluated and dispositioned as a TLAA for the Reactor Vessel, Reactor Vessel Vents and Drains System, the Reactor Recirculation System, the Reactor Core Isolation Cooling

System, the High Pressure Coolant Injection System, the Residual Heat Removal System, the Core Spray System, the Main Steam System, and the Reactor Feedwater System as discussed in Section 4.3.

Table 3.1.1 Item Number 3.1-1, 007: This item evaluates stainless steel, steel (with or without nickel alloy or stainless steel cladding), and nickel alloy reactor vessel components including nozzles, penetrations, safe ends, thermal sleeves, vessel shells, heads, and welds exposed to reactor coolant for cumulative fatigue damage due to fatigue and cyclic loading. Cumulative fatigue damage of carbon steel, carbon or low alloy steel with nickel alloy cladding, carbon or low alloy steel with stainless steel cladding, nickel alloy, and stainless steel penetrations, nozzles, safe ends, vessel internal attachments, vessel shell components, and associated welds is evaluated and dispositioned as a TLAA for the Reactor Vessel and Reactor Vessel Internals Systems as discussed in Section 4.3.

Table 3.1.1 Item Number 3.1-1, 011: This item evaluates steel and stainless steel pump and valve closure bolting exposed to high temperature and thermal cycles for cumulative fatigue damage due to fatigue and cyclic loading. Cumulative fatigue damage of carbon and low alloy steel bolting, and high strength low alloy steel bolting is evaluated and dispositioned as a TLAA for the Reactor Vessel, the Reactor Vessel Vents and Drains System, the Reactor Recirculation System, the Reactor Core Isolation Cooling System, and the High Pressure Coolant Injection System as discussed in Section 4.3.

Table 3.1.1 Item Number 3.1-1, 002, Item Number 3.1-1, 005, Item Number 3.1-1, 008, Item Number 3.1-1, 009, and Item Number 3.1-1, 010: These items are applicable to Pressurized Water Reactors (PWRs) only, and therefore are not used for BFN.

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).*

   Table 3.1.1 Item Number 3.1-1, 012: This item is applicable to PWRs only, and therefore is not used for BFN.

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.

Table 3.1.1 Item Number 3.1-1, 012: This item is applicable to PWRs only, and therefore is not used for BFN.

3.1.2.2.3 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement

1. *Neutron irradiation embrittlement is a TLAA to be evaluated for the subsequent period of extended operation for all ferritic materials that have a neutron fluence greater than 10^{17} n/cm2 (E >1 MeV) at the end of the subsequent period of extended operation. Certain aspects of neutron irradiation embrittlement are TLAAs as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.2, "Reactor Vessel Neutron Embrittlement Analysis," of this SRP-SLR.*

   Table 3.1.1 Item Number 3.1-1, 013: This item addresses loss of fracture toughness due to neutron irradiation embrittlement in 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. The BFN reactor vessel beltline shell, nozzle, and weld components are carbon or low alloy steel with stainless steel cladding. The evaluation of neutron irradiation embrittlement for all ferritic reactor vessel shell components and welds that have a projected neutron fluence value greater than 1 x 10^{17} n/cm^2 (E>1 MeV) at the end of the subsequent license renewal term is performed as a TLAA as discussed in Section 4.2.

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."

   <u>Table 3.1.1 Item Number 3.1-1, 014:</u> This item addresses loss of fracture toughness due to neutron irradiation embrittlement in 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. The Reactor Vessel Material Surveillance program (B.2.1.19) in conjunction with the Neutron Fluence Monitoring program (B.3.1.2) will be implemented to manage loss of fracture toughness due to neutron irradiation embrittlement of the carbon or low alloy steel with stainless steel cladding reactor vessel beltline components and welds exposed to a reactor coolant and neutron flux environment.

   The BFN Reactor Vessel Material Surveillance program meets the requirements of 10 CFR Part 50, Appendix H via BFN's participation in the BWRVIP Integrated Surveillance Program (ISP) in lieu of a plant-specific capsule removal and testing schedule. For Units 1, 2, and 3, ISP implementation and surveillance specimen schedule withdrawal and testing for the original 40 year operating license and the License Renewal period of extended operation is governed and controlled by BWRVIP-86 Revision 1-A, the BWRVIP responses to NRC Requests for Additional Information dated May 30, 2001, and December 22, 2001, and the NRC Safety Evaluation dated February 1, 2002 (Note: BWRVIP-86, Revision 1-A was approved by the NRC and issued in October 2012, superseding both BWRVIP-86-A and BWRVIP-116). For the SLR subsequent period of extended operation, the ISP will be extended through the subsequent period of extended operation in accordance with BWRVIP-321 Revision 1-A, “Boiling Water Reactor Vessel and Internals Project Plan for Extension of the BWR Integrated Surveillance Program (ISP) Through the Second License Renewal (SLR),” which has been reviewed and approved by the NRC. The plan established in BWRVIP-321 Revision 1-A not only satisfies the requirements of 10 CFR 50 Appendix H for an ISP through the subsequent period of extended operation, it also meets NRC expectations for an ISP in the subsequent period of extended operation as stated in NUREG-2191.

Two BFN Unit 2 test specimen surveillance capsules have previously been withdrawn and tested as part of the original plant-specific capsule removal and testing schedule and the ISP. An additional BFN Unit 2 test specimen surveillance capsule is scheduled for withdrawal during the License Renewal period of extended operation. ISP capsules that are designated for withdrawal and testing during the period of extended operation are designated as ISP(E) capsules to differentiate them from the ISP capsules withdrawn during the original license period. This ISP(E) capsule is the third set of Unit 2 test specimens, located at Azimuth 300°, which are currently scheduled for removal in the refueling outage closest to, but without exceeding, 40 Effective Full Power Years (EFPY) of operation. At the present time, this would correspond to Unit 2 Refueling Outage 25 (U2R25) in 2029. The BWRVIP ISP, as currently constituted and approved by NRC, does not require additional BFN capsule withdrawals beyond the third BFN Unit 2 capsule. It is noted that in Table 7-1 of BWRVIP-86, Revision 1-A, it is stated that the third set of Unit 2 test specimens are scheduled for withdrawal in 2026. However, the BWRVIP ISP recognizes that some uncertainty exists in the projections for the exact year plants will reach the target EFPY; therefore, the BWRVIP closely coordinates with the ISP plants and informs the NRC of any schedule changes that exceed two years of the scheduled removal. A review of the current ISP(E) capsule withdrawal schedule has recently been performed by the BWRVIP, which considered such things as recent early plant shutdowns, adjustments due to refuel outage schedules, more recent fluence calculations, estimated lead factors and capacity factors, as well as changes in plant operation that could impact the fleet and the ISP host capsule withdrawal and testing program. Schedule changes to the ISP(E) capsule withdrawal schedule are under consideration, including a possible delay to the withdrawal of the third set of Unit 2 test specimens, located at Azimuth 300° from 2026 until the Spring of 2029. This schedule change, if it is implemented by the BWRVIP ISP, will be reflected in a future supplement of the BFN SLRA if it becomes official prior to NRC approval of the BFN SLRA.

BWRVIP-321 Revision 1-A documents the plan for meeting ISP requirements through the 80 years of operation (SLR) for the U.S. BWR fleet. The plan calls for installation of a single Supplemental SLR (SSLR) capsule holder in a host plant to obtain the needed catch-up fluence to support 80 years of operation for the U.S. fleet. The single SSLR capsule holder will contain three capsules which correspond to 3 capsule grouping (Groups 1, 2, and 3) that are defined in BWRVIP-321 Revision 1-A based on the amount of catch-up fluence needed for the ISP representative material specimens to attain a neutron fluence that meets or exceeds (by up to a factor of 2) the target reactor vessel fluence for 80 years or operation, within a desired time frame of 10 years or less. Group 1 requires the lowest amount of catch-up fluence, while Group 3 requires the largest amount of catch-up fluence. The ISP representative material specimens for BFN are assigned to either Group 1 or Group 2.

The approach that the BWRVIP ISP is using to expand the program for the subsequent period of extended operation, is to ensure that all ISP representative materials have specimens that are irradiated to a fluence that bounds the SLR fluences of all target materials represented by that surveillance material. This will be accomplished by irradiating, reconstituting, and testing previously-tested ISP capsule materials as necessary to ensure that any plant which pursues SLR will have appropriate data available for its representative materials.

When all remaining capsules are tested under the ISP for the License Renewal period of extended operation, the current set of representative material specimens will have been fully used, with the exception of potential existing reconstituted capsules. For materials which require additional surveillance data, previously tested specimens from the BWRVIP ISP repository will be used for reconstitution. New Charpy test specimens will be fabricated by machining an insert, or central portion of the test specimen, from the broken Charpy halves and welding end tabs to the insert. Prior to reconstitution, the specimen inserts will be placed into specially designed SSLR capsules and be reinserted into a host reactor vessel to continue to irradiate the specimens to accumulate sufficient fluence to meet or exceed 80-year projected reactor vessel fluences. All SSLR capsules will be irradiated in one host plant. After irradiation is complete, reconstituted specimens will be fabricated and tested only for those materials that are needed by BWRs pursuing SLR.

The BWRVIP has selected the reactor that will serve as the SSLR capsule host plant. As part of the selection process, a plant-specific analysis was performed to determine the neutron flux profiles and fluence that can be expected at the proposed SSLR capsule location between the Core Shroud and the reactor vessel inside wall for each fuel type that the host plant plans to load on the core periphery in the future. This includes an advanced fuel design with improved neutronic efficiency design which yields a significantly lower neutron leakage flux than current designs. The analysis indicated that the capsule withdrawal schedule approved by the NRC in the original BWRVIP-321-A is no longer suitable for the ISP for SLR due in large part to the lower neutron flux that the SSLR capsule will be subjected to after the loading of the advanced fuel design on the periphery. Consequently, 12 years of irradiation will be required to attain the needed catch-up fluence for the Group 3 SSLR capsule. A revised SSLR capsule withdrawal schedule has been reviewed and approved by the NRC on December 14, 2022 (ADAMS Accession No. ML22290A191). The revised schedule specifies that all three SSLR capsules/ groups be irradiated for the full 12 years. The original schedule proposed in BWRVIP-321-A specified separate irradiation periods/capsule withdrawals for each capsule group. Elimination of intermediate capsule withdrawals for Groups 1 and 2 significantly reduces the costs and risks associated with the ISP. It was recognized that by irradiating all three capsules for the full 12 years, the Group 1 and Group 2 capsules will be exposed to neutron fluence levels significantly beyond their projected plant specific accumulated fluence levels at 80 years of operation. However, the highest expected fluence level for these capsules is still well below the fluence values where any unusual ΔRT_{NDT} values might be expected. Accordingly, no unusual embrittlement trends are expected for these BWR surveillance materials. The revised withdrawal schedule is contained in Appendix F of BWRVIP-321, Revision 1-A.

Based on this revised withdrawal schedule, all three of the SSLR capsules will be installed in host reactor in the Fall of 2023 and withdrawn 12 years later in the Fall of 2035. When the SLRA for BFN is approved, Unit 1 will enter the subsequent period of extended operation on December 20, 2033, Unit 2 will enter the subsequent period of extended operation on June 28, 2034, and Unit 3 will enter the subsequent period of extended operation on July 2, 2036. Thus, the revised withdrawal schedule will result in the withdrawal of the SSLR capsule holder before any BFN unit progresses significantly (at most 2 years) into its subsequent period of extended operation.

The reserved surveillance capsules from BFN Units 1 and 3, represent reactor vessel material surveillance resources that could be employed to support further license extensions. BFN is committed to the BWRVIP ISP program and will support the program through additional capsule withdrawals as deemed appropriate by the BWRVIP and NRC. Presently, there are no plans to withdrawal any capsules from either Unit 1 or Unit 3, as the BFN Unit 2 capsules provide the best representative plate material for all three units and the best representative weld material for Units 2 and 3 (the best representative weld material for Unit 1 was found in capsules pulled from other plants as part of the BWR Owners' Group Supplemental Surveillance Program). Although the surveillance capsules for Units 1 and 3 will be deferred and not tested as part of the ISP, these capsules that were previously credited as part of BFN plant-specific surveillance programs will continue to be irradiated in their host reactors.

The Neutron Fluence Monitoring program (B.3.1.2) will be used to monitor the neutron fluence levels that are used as the time-dependent inputs for the time-limited aging analyses (TLAAs) that evaluate loss of fracture toughness due to 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.*

Table 3.1.1 Item Number 3.1-1, 015: This item is applicable to PWRs only, and therefore is not used for BFN.

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.*

Table 3.1.1 Item Number 3.1-1, 016: This item evaluates cracking due to stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC) in stainless steel or nickel alloy reactor vessel flange leak detection lines exposed to air-indoor uncontrolled or reactor coolant leakage environments. Plant-specific OE associated with the stainless steel or nickel alloy piping and piping components in the Reactor Vessel System, including the reactor vessel flange leak detection lines, has been evaluated to determine if cracking due to SCC or IGSCC has occurred in the reactor vessel flange leak detection lines. The OE evaluation did not identify any occurrences of cracking due to SCC or IGSCC in the BFN reactor vessel flange leak detection lines. Accordingly, the One-Time Inspection (B.2.1.20) program will be implemented to demonstrate that the aging effect of cracking due to SCC, IGSCC is not occurring in the stainless steel or nickel alloy reactor vessel top head enclosure flange leakage detection line exposed to air-indoor uncontrolled or reactor coolant leakage environments. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection program (B.2.1.20) is described in Appendix B.

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).*

   Table 3.1.1 Item Number 3.1-1, 017: This item is not used since the BFN Boiling Water Reactor (BWR) design does not include an isolation condenser.

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[1]. 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).

Table 3.1.1 Item Number 3.1-1, 018: This item is applicable to PWRs only, and therefore is not used for BFN.

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).*

   Table 3.1.1 Item Number 3.1-1, 019: This item is applicable to PWRs only, and therefore is not used for BFN.

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).*

   Table 3.1.1 Item Number 3.1-1, 020: This item is applicable to PWRs only, and therefore is not used for BFN.

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.*

   Table 3.1.1 Item Number 3.1-1, 139: This item is applicable to PWRs only, and therefore is not used for BFN.

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).*

Table 3.1.1 Item Number 3.1-1, 021: This item is not used since the BFN BWR design does not include an isolation condenser.

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).

Table 3.1.1 Item Number 3.1-1, 022: This item is applicable to PWRs only, and therefore is not used for BFN.

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 (MRP) identified that the following aging mechanisms may be applicable to the design of the RVI components in these types of facilities: (a) SCC, (b) irradiation-assisted stress corrosion cracking (IASCC), (c) fatigue, (d) wear, (e) neutron irradiation embrittlement, (f) thermal aging embrittlement, (g) void swelling and irradiation growth, or (h) thermal or irradiation- enhanced stress relaxation or irradiation enhanced creep. The methodology in MRP-227-A was approved by the NRC in a safety evaluation dated December 16, 2011 (ADAMS Accession No. ML11308A770), which includes those plant-specific applicant/licensee action items that a licensee or applicant applying the MRP-227-A report would need to address and resolve and apply to its licensing basis.

The EPRI MRP's functionality analysis and failure modes, effects, and criticality analysis bases for grouping Westinghouse-designed, B&W-designed and Combustion Engineering (CE)-designed RVI components into these inspection categories was based on an assessment of aging effects and relevant time-dependent aging parameters through a cumulative 60-year licensing period (i.e., 40 years for the initial operating license period plus an additional 20 years during the initial period of extended operation). The EPRI MRP has not assessed whether operation of Westinghouse-designed, B&W-designed and CE-designed reactors during an SLR operating period would have any impact on the existing susceptibility rankings and inspection categorizations for the RVI components in these designs, as defined in MRP-227-A or its applicable MRP background documents (e.g., MRP-191 for Westinghouse-designed or CE-designed RVI components or MRP-189 for B&W-designed components).

As described in GALL-SLR Report AMP XI.M16A, the applicant may use the MRP-227-A based AMP as an initial reference basis for developing and defining the AMP that will be applied to the RVI components for the subsequent period of extended operation. However, to use this alternative basis, GALL-SLR Report AMP XI.M16A recommends that the MRP-227-A based

AMP be enhanced to include a gap analysis of the components that are within the scope of the AMP. The gap analysis is a basis for identifying and justifying any potential changes to the MRP-227-A based program that may be necessary to provide reasonable assurance that the effects of age-related degradation will be managed during the subsequent period of extended operation. The criteria for the gap analysis are described in GALL-SLR Report AMP XI.M16A.

Alternatively, the PWR SLRA may define a plant-specific AMP for the RVI components to demonstrate that the RVI components will be managed in accordance with the requirements of 10 CFR 54.21(a)(3) during the proposed subsequent period of extended operation. Components to be inspected, parameters monitored, monitoring methods, inspection sample size, frequencies, expansion criteria, and acceptance criteria are justified in the SLRA. The NRC staff will assess the adequacy of the plant-specific AMP against the criteria for the 10 AMP program elements that are defined in Section A.1.2.3 of SRP-SLR Appendix A.1.

Table 3.1.1 Item Numbers 3.1-1, 028, 3.1-1, 051a, 3.1-1, 051b, 3.1-1, 052a, 3.1-1, 052b, 3.1-1, 052c, 3.1-1, 053a, 3.1-1, 053b, 3.1-1, 053c, 3.1-1, 055a, 3.1-1, 055b, 3.1-1, 055c, 3.1-1, 056a, 3.1-1, 056b, 3.1-1, 056c, 3.1-1, 058a, 3.1-1, 058b, 3.1-1, 059a, 3.1-1, 059b, 3.1-1, 059c, 3.1-1, 118, and 3.1-1, 119: These items are applicable to PWRs only, and therefore are not used for BFN.

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).*

   Table 3.1.1 Item Number 3.1-1, 116: This item is applicable to PWRs only, and therefore is not used for BFN.

2. *Industry OE indicates that loss of material due to wear can occur in the SS thermal sleeves of PWR CRD head penetration nozzles due to the interactions between the nozzle and the thermal sleeve (e.g., where the thermal sleeve exits from the head penetration nozzle inside the reactor vessel as described in 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.*

   Table 3.1.1 Item Number 3.1-1, 117: This item is applicable to PWRs only, and therefore is not used for BFN.

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.*

<u>Table 3.1.1 Item Number 3.1-1, 025:</u> This item is applicable to PWRs only, and therefore is not used for BFN.

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.

<u>Table 3.1.1 Item Number 3.1-1, 025:</u> This item is applicable to PWRs only, and therefore is not used for BFN.

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.

<u>Table 3.1.1 Item Number 3.1-1, 029, Item Number 3.1-1, 041, and Item Number 3.1-1, 103:</u>
These items evaluate cracking including irradiated assisted stress corrosion cracking (IASCC) in stainless steel and nickel alloy reactor vessel internal components exposed to reactor coolant with neutron flux. Due to the increase in neutron fluence during the subsequent period of extended operation, an evaluation was performed to determine if supplemental inspections are necessary in addition to those recommended in the existing BWRVIP guidelines.

BFN Units 1, 2 and 3 will utilize the BWR Vessel Internals aging management program to manage age-related degradation of stainless steel and nickel alloy reactor vessel internal components and welds that are susceptible to cracking due to IASCC. The BFN BWR Vessel Internals program (B.2.1.7) is based on the recommendations provided in GALL-SLR AMP XI.M9, BWR Vessel Internals, and implements the referenced BWRVIP guidelines, as applicable. Supplemental inspections to manage IASCC beyond the current BWRVIP guidance are not necessary based on the following evaluation.

The aging mechanism of IASCC is dependent on accumulated neutron irradiation fluence. IASCC degradation of stainless steel or nickel alloys, including welds is not considered to be plausible until an accumulated neutron irradiation fluence threshold has been exceeded. A threshold fluence level for IASCC of 5.0×10^{20} n/cm^2 (E>1 MeV) has been generally accepted and is specified in BWRVIP guidance such as BWRVIP-26-A: BWR Vessel and Internals Project BWR Top Guide Inspection and Flaw Evaluation Guidelines. BWRVIP guidance addresses IASCC through 1) periodic inspection requirements for components using techniques capable of detecting cracking due to SCC and 2) flaw tolerance guidance that considers the effect of neutron fluence on material properties and SCC growth rates.

Although a generic threshold neutron irradiation fluence of 5×10^{20} n/cm^2 (E>1 MeV) has been generally accepted for onset of IASCC and used as a screening threshold for IASCC applicability, there is little evidence that accumulation of neutron irradiation fluence beyond this threshold results in increased stress corrosion cracking (SCC) occurrence. Periodic examinations of BWR internals subject to neutron irradiation fluence much greater than the threshold (i.e., core shrouds and top guide assemblies) have been performed for many years. To date, these inspections have not identified clear evidence of SCC initiation associated with increased neutron irradiation fluence. In most cases, newly identified cracking is attributed to application of new or more sensitive Non-Destructive Examination (NDE) technologies or implementation of NDE systems that permit probe delivery to locations previously not accessible.

However, during scheduled Enhanced Visual Testing (EVT-1) visual examinations of five Top Guide Grid Beam locations performed during BFN Unit 1 Refueling Outage 14 (U1R14), a relevant indication was observed at the northeast slotted notch of Cell Location 22-47. The indication traveled from the upper tip of the slotted notch diagonally upward and to the west along the grid beam for approximately 0.5". The indication had a horizontal component of 0.497" and a vertical component of 0.138". The most probable cause of the indication was postulated to be IASCC.

In accordance with EPRI Document BWRVIP-183-A, “Top Guide Grid Beam Inspection and Flaw Evaluation Guidelines,” Section 8.2, no scope expansion was required during U1R14 due to the identification of the indication since complete severance of the grid beam had not occurred. However, per Note 2 of Table 8-2 of BWRVIP-183-A, a plant-specific evaluation was performed for this flaw to determine a critical flaw size for the grid beam which was then used to determine if inspection scope expansion would be required during the following Unit 1 Refueling Outage 15 (U1R15). The evaluation concluded that the indication emanating from the northeast slotted notch of Cell Location 22-47 was below 75% of the beam height and would remain so throughout the next operating cycle. Therefore, the flaw was determined to be acceptable without repair per BWRVIP-183-A, since the flaw was verified by plant specific evaluation to be less than a critical flaw size that would result in failure. However, follow-up examination was added to the scope of future Unit 1 Refueling Outages 15 and 16 (U1R15 in the Fall of 2024 and U1R16 in the Fall of 2026) to evaluate the stability of the flaw as defined in Section 8.4 of BWRVIP 183-A with no further scope expansion required in future outages.

Regardless of operating experience trends, component locations potentially susceptible to IASCC are in all cases evaluated for significance of failure and if determined necessary, are subject to periodic inspection in accordance with the BWRVIP guideline applicable to the component. BWRVIP inspection requirements are conservatively established based considerations that include fleet performance, flaw tolerance, and redundancy. Inspection methods determined to be adequate to detect tight SCC remain adequate to detect IASCC in regions of increased neutron irradiation fluence.

The primary impact of increased neutron irradiation associated with operation beyond 60 years, is the effect on flaw tolerance evaluations. Flaw tolerance evaluation inputs include material fracture toughness and SCC crack growth rate, both of which can be affected by neutron fluence. Although these evaluation inputs can be affected by accumulated neutron fluence, the methods recommended within existing BWRVIP guidance remain adequate for use by licensees to determine the proper re-inspection interval. The application of fracture mechanics tools for the management of vessel internals is not limited by any specific time period. Further, although increased neutron fluences may potentially affect the re-inspection interval allowed, the tools remain valid for use at any fluence anticipated for boiling water reactors.

The following BFN Units 1, 2 and Unit 3 reactor vessel internal components are projected to exceed a neutron irradiation fluence of $5x10^{20}$ n/cm^2 (E>1 MeV) prior to the end of the subsequent period of extended operation; top guide, core shroud, core plate, in-core monitor dry tubes, in-core monitor housings, control rod guide tube housings (upper portion only) and orificed fuel supports. The evaluations to determine whether supplemental inspections are necessary in addition to those recommended in the existing BWRVIP examination guidelines are provided below.

Top Guide - Current inspection recommendations for the top guide are provided in BWRVIP-26-A, “BWR Vessel and Internals Project, BWR Top Guide Inspection and Flaw Evaluation Guidelines” and BWRVIP-183-A, “BWR Vessel and Internals Project, Top Guide Grid Beam Inspection and Flaw Evaluation Guidelines.” Both BWRVIP-26-A and BWRVIP-183-A consider IASCC an applicable aging mechanism in the determination of the inspection recommendations. Therefore, supplemental inspections in addition to the existing recommended inspections, which will continue through the subsequent period of extended operation,are not necessary.

Core Shroud - Current inspection recommendations for the core shroud are provided in BWRVIP-76-R1-A, “BWR Vessel and Internals Project, BWR Core Shroud Inspection and Flaw Evaluation Guidelines.” IASCC is identified as one of the observed mechanisms associated with cracking of core shrouds in the industry. The inspection recommendations provided in BWRVIP-76-R1-A are based on inspection results and flaw tolerance evaluations that appropriately consider the effects of neutron fluence on material fracture toughness and SCC crack growth rate correlations. Therefore, the higher neutron fluence achieved during the subsequent period of extended operation is addressed as part of the current guidance provided in BWRVIP-76-R1-A. Since the core shroud inspections are based on previous inspection results and flaw tolerance evaluations that consider the effects of neutron fluence, supplemental inspections in addition to the currently recommended inspection guidance, which will continue to be applicable through the subsequent period of extended operation, are not necessary.

Core Plate - Current inspection recommendations for the core plate are provided in BWRVIP-25 Revision 1-A, “BWR Vessel and Internals Project, BWR Core Plate Inspection and Flaw Evaluation Guidelines.” Structural evaluations conducted as part of developing BWRVIP-25 Revision 1-A concluded that no examinations are required for the core plate since postulated cracking cannot have an adverse effect on the capability of the core plate to perform its intended function. Supplemental inspections in addition to the guidance provided in BWRVIP-25 Revision 1-A are not necessary since cracking of the core plate will not prevent the core plate from performing its intended function.

For many core plate weld locations, there are no safety consequences from degradation. Elsewhere, the location is redundant to the core plate bolts and, as a result, inspection is not required. Significant SCC crack growth is not anticipated for locations fully protected by Hydrogen Water Chemistry (HWC), Noble Metal Chemistry Addition (NMCA), or Online Noble Metal Chemistry (OLNC) (as are the vessel internals at BFN). The location of most significance, in addition to the core plate bolts, are the aligner pin assemblies, which are redundant to the core plate bolts. These pins are located in a low fluence region of the core plate; in a region where neutron fluence exceeding the $5x10^{20}$ n/cm^2 (E > 1.0 MeV) threshold for IASCC is not considered to be plausible, regardless of service life.

For the core plate welded structure, there are no factors associated with extended operation that would indicate a change to these conclusions. Although some additional cracking could be postulated during extended operation, there are no data supporting any adverse trend for locations protected by HWC, NMCA, or OLNC, even when neutron fluence approaches or exceeds the IASCC threshold fluence of $5x10^{20}$ n/cm^2 (E > 1.0 MeV). Finally, there is no direct time dependency associated with the safety assessment conclusions documented in BWRVIP-25, Revision 1-A that form the basis for the current aging management approach.

In-core Monitor Dry Tubes - Current inspection recommendations for the in-core monitor dry tubes are provided in BWRVIP-47-A, "BWR Vessel and Internals Project, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines." BWRVIP-47-A considered IASCC an applicable aging mechanism in the determination of the inspection recommendations, therefore supplemental inspections in addition to the existing recommended inspections are not necessary.

In-core Monitor Housing - Current inspection recommendations for the in-core monitor housings are provided in BWRVIP-47-A, "BWR Vessel and Internals Project, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines." No inspections of the in-core monitor housings are recommended by BWRVIP-47-A. This recommendation is based on the determination that a failure of an in-core monitor housing does not impair the safe shutdown of the plant and the failure of an in-core monitor for any reason would be detectable by loss of monitor indication. The inclusion of IASCC to the applicable aging effects does not change the current conclusions of BWRVIP-47-A, therefore supplemental inspections or enhancements to the BWRVIP guidance are not necessary.

Control Rod Guide Tube Housing - Current inspection recommendations for the control rod guide tube housing are provided in BWRVIP-47-A, "BWR Vessel and Internals Project, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines." BWRVIP-47-A recommends performing baseline inspections of the Control Rod Guide Tube (CRGT) to alignment lug weld (CRGT-1) and the guide tube circumferential welds (CRGT-2 and CRGT-3). These baseline inspections were performed at BFN during the 2004 to 2011 timeframe and no recordable indications were observed.

The BWRVIP-47-A recommended baseline inspection of the CRGT-1 welds consisted of a VT-3 visual inspection or verification of the alignment lug during removal and installation of the orificed fuel support. Although re-inspection of CRGT-1 welds is not currently required, the orificed fuel supports are removed and installed during control rod blade replacement activities which occur routinely. Also, the failure of the CRGT-1 weld was determined to have no safety consequence as evaluated in BWRVIP-47-A and BWRVIP-06 Revision 1-A. Based on the verification of the alignment lug during control rod blade replacement activities and no safety consequences associated with a failed alignment lug, supplemental inspections or enhancements to the current BWRVIP guidance for CRGT-1 welds are not necessary.

The BWRVIP-47-A recommended baseline inspection of the CRGT-2 and CRGT-3 welds consisted of an EVT-1 visual inspection. All U.S. BWRs have performed a baseline inspection of 10% of the CRGTs. As previously noted, these baseline inspections were performed at BFN during the 2004 to 2011 timeframe and no recordable indications were observed. Out of these inspections, very few relevant indications have been reported in the fleet, including only one short indication associated with a CRGT-2 weld and a small number of loose fuel alignment pins. As discussed in BWRVIP-06 Revision 1-A during normal plant operation the control rod guide tube and the CRGT welds are under compression and a failure is not expected to prevent control rod movement unless horizontal displacement or buckling was to occur. Significant horizontal displacement or buckling which would prevent control rod movement is not expected unless an event such as a LOCA or seismic event occurs when an undetected weld failure is present. Multiple control rod guide tube failures, which are considered to be a very low probability, would be required to prevent safe shutdown of the plant. Re-inspection of the CRGT-2 and CRGT-3 welds is not currently required, however control rod guide tubes are visually inspected for cleanliness and foreign material during control rod blade replacement activities which occur routinely. Any gross failure of the CRGT-2 or CRGT-3 welds could be detected during this activity.

With regard to IASCC / irradiation embrittlement, the upper end of the CRGT assemblies, in the area of the core plate and including welds CRGT-1 and CRGT-2, are projected to accumulate fluence exceeding the IASCC threshold fluence prior to the end of the subsequent period of extended operation. However, the CRGT-1 alignment lug function is redundant to that provided by the orificed fuel support casting alignment slot. As such, cracking in this location will not result in a critical failure. At the CRGT-2 weld location, the accumulated fluence is significantly lower, but it still may be potentially near the IASCC threshold fluence for welded components. However, there is no evidence that fluence near $5x10^{20}$ n/cm^2 (E > 1.0 MeV) will result in new SCC initiations. As such, there is presently no basis for any near-term concern at this location.

The results of the BWR fleet baseline inspections have been very favorable, and application of HWC technologies will likely prevent any future SCC occurrences. However, some nominal potential for SCC may be possible. Different than other BWRVIP guidelines, BWRVIP-47-A does not include periodic inspection requirements. As such, an evaluation is therefore appropriate to assess the periodic inspection needs to ensure adequate aging management. To address this need, the BWRVIP has initiated a project to review relevant data associated with CRGTs and CRD housings and perform associated engineering evaluations with the intent of determining if the inspection recommendations in BWRVIP-47-A are adequate or in need of Revision, and establishing appropriate future guidance for managing these components if appropriate.

Based on no indications being identified during the initial baseline inspections, the CRGT welds being under compression during normal plant operation, the low probability of multiple CRGT welds being failed concurrent with a LOCA or seismic event, control rod guide tubes are visually inspected for cleanliness and foreign material during control rod blade replacement activities, supplemental inspections or enhancements to the current BWRVIP guidance are not necessary in the near term. Nonetheless, as noted above, the BWRVIP intends to address re-inspection needs for CRGTs and CRD housings in a future Revision to BWRVIP-47-A. Evaluations supporting a Revision to BWRVIP-47-A will include consideration of the fluence accumulated for operation beyond 60 years and ensure that the conclusions reached are applicable to extended operations. Any new or revised inspection recommendations are required to be implemented at BFN by TVA in accordance with BWRVIP-94-R3-NP, “BWR Vessel and Internals Project, Program Implementation Guide” and Nuclear Energy Institute (NEI) guideline NEI 03-08, “Guideline for the Management of Material Issues.”

Orificed Fuel Support - Current inspection recommendations for the orificed fuel supports are provided in BWRVIP-47-A, “BWR Vessel and Internals Project, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines.” No inspections of the orificed fuel supports are recommended by BWRVIP-47-A. This recommendation is based on assessments in BWRVIP-47-A and BWRVIP-06 Revision 1-A: BWR Vessel and Internals Project, Safety Assessment of BWR Reactor Internals, which concludes that the orificed fuel support castings are highly resistant to impairment by cracking due to the one-piece fabrication, the fact that cracking has not been observed, and that shutdown could be achieved even if a local failure did occur. The inclusion of IASCC to the applicable aging effects does not change the current conclusions of BWRVIP-47-A and BWRVIP-06 Revision 1-A, therefore supplemental inspections or enhancements to the BWRVIP guidance are not necessary.

As discussed above, specifying supplemental inspections beyond the inspections recommended by the current BWRVIP guidelines is not necessary. The BWRVIP is chartered to review and trend operating experience from the BWR fleet relative to implementation of recommended inspections and revise the recommendations as appropriate in accordance with BWRVIP-94-R3-NP and NEI 03-08. As new or revised inspection recommendations are recommended by the BWRVIP, the recommendations are required to be implemented in accordance with BWRVIP-94-R3-NP and NEI 03-08.

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.

<u>Table 3.1.1 Item Number 3.1-1, 099:</u> This item evaluates loss of fracture toughness due to neutron irradiation or thermal aging embrittlement in stainless steel (including cast austenitic stainless steel (CASS), martensitic stainless steel, and precipitation-hardened (PH) martensitic stainless steel) and nickel alloy (including X-750 alloy) reactor vessel internal components exposed to reactor coolant with neutron flux. Due to the increase in neutron fluence during the subsequent period of extended operation, an evaluation was performed to determine if supplemental inspections are necessary in addition to those recommended in the existing BWRVIP guidelines.

The materials used to construct the BFN Units 1, 2, and 3 reactor vessel internals consist of CASS, wrought austenitic stainless steel, and nickel alloys (including alloy 600 and X- 750). Precipitation-hardened (PH) martensitic SS (e.g., 15-5 and 17-4 PH steel) and martensitic SS (e.g., 403, 410, 431 steel) were not used in fabrication of any reactor vessel internal component or repair component for BFN Units 1, 2 and 3.

The CASS reactor vessel internal components consist of the following; jet pump assembly (transition piece including elbow, inlet mixer, and diffuser collar), jet pump restrainer bracket, core spray sparger elbows, control rod guide tube base, and orificed fuel support castings. The aging effect of loss of fracture toughness due to thermal aging embrittlement and neutron irradiation embrittlement on these CASS components was specifically evaluated in BWRVIP-234, “BWR Vessel and Internals Project, Thermal Aging and Neutron Embrittlement Evaluation of Cast

Austenitic Stainless Steels for BWR Internals." The BWRVIP-234 evaluation determined that no supplemental (augmented) inspections, beyond those recommendations within the current BWRVIP reports were needed for these components to manage the aging effect of loss of fracture toughness due to thermal aging embrittlement and neutron irradiation embrittlement. The NRC accepted this recommendation, as adequately managing loss of fracture toughness due to thermal embrittlement and irradiation embrittlement and any possible combined effects of the two, for components that do not exceed $6x10^{20}$ n/cm^2 (1 dpa) as documented in Final Safety Evaluation of the BWRVIP-234, "Thermal Aging Embrittlement Evaluation of Cast Austenitic Stainless Steel for BWR Internals," dated June 22, 2016 (ADAMS Accession No. ML16096A002). For BFN Units 1, 2 and 3, the only CASS components that are projected to exceed a fluence greater than $6x10^{20}$ n/cm^2 (E>1 MeV) prior to the end of the subsequent period of extended operation are the orificed fuel support castings. Therefore, supplemental inspections or enhancements to the BWRVIP guidance are not necessary for the jet pump assembly (transition piece including elbow, inlet mixer, and diffuser collar), jet pump restrainer bracket, core spray sparger elbows, and control rod guide tube base.

The orificed fuel support castings were determined to be not susceptible to loss of fracture toughness due to thermal aging embrittlement based on being statically cast using CF-8 low molybdenum material and a delta ferrite content of less than 20 percent. However, the orificed fuel support castings in high fluence areas are projected to exceed the threshold of $6x10^{20}$ n/cm^2 (E>1 MeV) for loss of fracture toughness due to neutron irradiation embrittlement. For loss of fracture toughness to have an effect on a component's intended function there must be a mechanism for crack initiation and propagation. During normal plant operation, the orificed fuel support castings are in compression due to the weight of the fuel assemblies they support, therefore tensile stresses to initiate cracking are not present. The orificed fuel support castings are cast from ferritic - austenitic duplex stainless steel which is highly resistant to intergranular stress corrosion cracking (IGSCC). In addition, hydrogen water chemistry treatment is used to mitigate the potential for IGSCC. An assessment documented in BWRVIP-06 Revision 1-A, "Safety Assessment of BWR Reactor Internals," concluded that the orificed fuel support castings are highly resistant to impairment by cracking due to one-piece fabrication. Based on the fact that cracking has not been observed and that shutdown could be achieved even if a local failure did occur, no short-term (or long-term) action is required. Based on the above, supplemental inspections or enhancements to the BWRVIP guidance are not necessary to manage loss of fracture toughness due to thermal aging embrittlement or neutron irradiation embrittlement for the orificed fuel support castings.

Wrought austenitic stainless steel and nickel alloy can experience loss of fracture toughness due to neutron embrittlement when exposure to high neutron fluence. Per MRP-175, Materials Reliability Program, "PWR Internals Material Aging Degradation Mechanism Screening and Threshold Values," the aging effect of loss of fracture toughness due to neutron irradiation embrittlement is applicable for components if the fluence exceeds $1x10^{21}$ n/cm^2 (E>1 MeV) for wrought austenitic stainless steel and $6.7x10^{20}$ n/cm^2 (E>1 MeV) for welded austenitic stainless steel. MRP-175 also specifies that the austenitic stainless steel criterion should be used to nickel alloys. Although this criterion was developed for PWRs, it is considered applicable for boiling water reactors. However, the impact of loss of fracture toughness is only significant if cracking occurs. Conservatively, the threshold for irradiation-assisted stress corrosion cracking (IASCC) of $5x10^{20}$ n/cm^2 (E>1 MeV) is applied as a reasonable lower bound fluence for consideration of loss of fracture toughness due to irradiation embrittlement. The wrought austenitic stainless steel reactor internal components and welds that are projected to exceed the fluence threshold for susceptibility to loss of fracture toughness due to neutron irradiation embrittlement ($5x10^{20}$ n/cm^2 (E>1 MeV)) are the top guide, core shroud, core plate, in-core monitor dry tubes, in-core monitor housing, and control rod guide tube housing.

Top Guide - The top guide is currently inspected periodically for cracking. Therefore, the aging effect of loss of fracture toughness due to neutron embrittlement can be indirectly managed by identifying aging degradation, implementing early corrective actions, and monitoring and trending age-related degradation. Current inspection recommendations for the top guide are provided in BWRVIP-26-A, “BWR Vessel and Internals Project, Top Guide Inspection and Flaw Evaluation Guidelines,” and BWR-183-A, “BWR Vessel and Internals Project, Top Guide Grid Beam Inspection and Flaw Evaluation Guidelines.” The inspection recommendations provided in BWRVIP-26-A and BWRVIP-183-A are based on inspection results and flaw tolerance evaluations that appropriately consider the effects of neutron fluence on material toughness and crack growth rate correlations. Since the top guide inspections are based on previous inspection results and flaw tolerance evaluations that consider the effects of neutron fluence, supplemental inspections in addition to the current recommended inspection guidance are not necessary since the higher neutron fluence achieved during the subsequent period of extended operation is addressed as part of the current guidance provide in BWRVIP-26-A and BWRVIP-183-A.

Core Shroud - The core shroud is currently inspected periodically for cracking. Therefore, the aging effect of loss of fracture toughness due to neutron embrittlement can be indirectly managed by identifying aging degradation, implementing early corrective actions, and monitoring and trending age-related degradation. Current inspection recommendations for the core shroud are provided in BWRVIP-76-R1-A, “BWR Vessel and Internals Project, BWR Core Shroud Inspection and Flaw Evaluation Guidelines.” The inspection recommendations provided in BWRVIP-76-R1-A are based on inspection results and flaw tolerance evaluations that appropriately consider the effects of neutron fluence on material toughness and crack growth rate correlations. Since the core shroud inspections are based on previous inspection results and flaw tolerance evaluations that consider the effects of neutron fluence, supplemental inspections in addition to the current recommended inspection guidance are not necessary since the higher neutron fluence achieved during the subsequent period of extended operation is addressed as part of the current guidance provide in BWRVIP-76-R1-A.

Core Plate - Current inspection recommendations for the core plate are provided in BWRVIP-25 Revision 1-A, “BWR Vessel and Internals Project, BWR Core Plate Inspection and Flaw Evaluation Guidelines.” Structural evaluations conducted as part of developing BWRVIP- 25 Revision 1-A, concluded that no examinations are required for the core plate since postulated cracking cannot have an adverse effect on the capability of the core plate to perform its intended function. Supplemental inspections in addition to the guidance provided in BWRVIP-25 Revision 1-A are not necessary since cracking of the core plate does not prevent the core plate from performing its intended function.

In-core Monitor Dry Tubes - Current inspection recommendations for the in-core monitor dry tubes are provided in BWRVIP-47-A, “BWR Vessel and Internals Project, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines.” No inspections of the in-core monitor dry tubes are recommended by BWRVIP-47-A. This recommendation is based on the determination that a failure of a dry tube does not impair the safe shutdown of the plant and the failure of an in-core monitor for any reason would be detectable by loss of monitor indication. The inclusion of loss of fracture toughness to the applicable aging effects does not change the current conclusions of

BWRVIP-47-A, therefore supplemental inspections or enhancements to the BWRVIP guidance are not necessary.

In-core Monitor Housing - Current inspection recommendations for the in-core monitor housings are provided in BWRVIP-47-A, “BWR Vessel and Internals Project, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines. No inspections of the in-core monitor housings are recommended by BWRVIP-47-A.” This recommendation is based on the determination that a failure of an in-core monitor housing does not impair the safe shutdown of the plant and the failure of an in-core monitor for any reason would be detectable by loss of monitor indication. The inclusion of loss of fracture toughness to the applicable aging effects does not change the current conclusions of BWRVIP-47-A, therefore supplemental inspections or enhancements to the BWRVIP guidance are not necessary.

Control Rod Guide Tube Housing - Current inspection recommendations for the control rod guide tube housing are provided in BWRVIP-47-A, “BWR Vessel and Internals Project, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines.” BWRVIP-47-A recommends performing baseline inspections of the guide tube to alignment lug weld (CRGT-1) and the guide tube circumferential welds (CRGT-2 and CRGT-3). These baseline inspections were performed at BFN during the 2004 to 2011 timeframe and no recordable indications were observed.

The upper portions of the control rod guide tube housing, in the area of the core plate, are projected to exceed the fluence threshold for neutron embrittlement. These portions include welds CRGT-1 and CRGT-2 in high fluence areas.

The BWRVIP-47-A recommended baseline inspection of the CRGT-1 welds consisted of a VT-3 visual inspection or verification of the alignment lug during removal and installation of the orificed fuel support. Although re-inspection of CRGT-1 welds is not currently required, the orificed fuel supports are removed and installed during control rod blade replacement activities which occur routinely. Also, the failure of the CRGT-1 weld was determined to have no safety consequence as evaluated in BWRVIP-47-A and BWRVIP- 06-R1-A. Based on the verification of the alignment lug during control rod blade replacement activities and no safety consequences associated with a failed alignment lug, supplemental inspections or enhancements to the current BWRVIP guidance are not necessary.

The BWRVIP-47-A recommended baseline inspection of the CRGT-2 and CRGT-3 welds consists of an EVT-1 visual inspection. All U.S. BWRs have performed a baseline inspection of 10% of the CRGTs. Out of these inspections, very few relevant indications have been reported in the fleet, including only one short indication associated with a CRGT-2 weld and a small number of loose fuel alignment pins. As discussed in BWRVIP-06 Revision 1-A during normal plant operation the control rod guide tube and CRGT-2 welds are under compression and a failure is not expected to prevent control rod movement unless horizontal displacement or buckling was to occur. Significant horizontal displacement or buckling which would prevent control rod movement is not expected unless an event such as a LOCA or seismic event occurs when an undetected weld failure is present. Multiple control rod guide tube failures, which are considered to be a very low probability, would be required to prevent safe shutdown of the plant. Re-inspection of CRGT-2 and CRGT-3 welds is not currently required, however control rod guide tubes are visually inspected for cleanliness and foreign material during control rod blade replacement activities which occur routinely. Any gross failure of the CRGT-2 or CRGT-3 welds could be detected during this activity.

The results of the BWR fleet baseline inspections have been very favorable, and application of HWC technologies will likely prevent any future SCC occurrences. However, some nominal potential for SCC may be possible. Different than other BWRVIP guidelines, BWRVIP-47-A does not include periodic inspection requirements. As such, an evaluation is therefore appropriate to assess the periodic inspection needs to ensure adequate aging management. To address this need, the BWRVIP has initiated a project to review relevant data associated with CRGTs and CRD housings and perform associated engineering evaluations with the intent of determining if the inspection recommendations in BWRVIP-47-A are adequate or in need of Revision, and establishing appropriate future guidance for managing these components if appropriate.

Based on no indications being identified during the initial baseline inspections, the CRGT welds being under compression during normal plant operation, the low probability of multiple CRGT welds being failed concurrent with a LOCA or seismic event, control rod guide tubes are visually inspected for cleanliness and foreign material during control rod blade replacement activities, supplemental inspections or enhancements to the current BWRVIP guidance are not necessary in the near term. Nonetheless, as noted above, the BWRVIP intends to address re-inspection needs for CRGTs and CRD housings in a future Revision to BWRVIP-47-A. Evaluations supporting a Revision to BWRVIP-47-A will include consideration of the fluence accumulated for operation beyond 60 years and ensure that the conclusions reached are applicable to extended operations. Any new or revised inspection recommendations are required to be implemented at BFN by TVA in accordance with BWRVIP-94-R4, “BWR Vessel and Internals Project, Program Implementation Guide,” and NEI 03-08, “Guideline for the Management of Material Issues.”

The nickel alloy reactor vessel internal components consist of the following; core shroud support assembly, core shroud access hole covers and bolting, jet pump hold-down beams, jet pump repair hardware (e.g., auxiliary spring wedges and slip joint clamps) and core spray repair hardware (e.g., clamps). The reactor vessel internal components fabricated from nickel alloy are located in relatively low fluence areas or were installed later in plant life (i.e., repair hardware). The projected fluence of the nickel alloy components at the end of the subsequent period of extended operation is less than $5x10^{20}$ n/cm^2, therefore loss of fracture toughness due to neutron irradiation embrittlement is not considered an applicable aging effect, therefore supplemental inspections or enhancements to the BWRVIP guidance are not necessary.

As discussed above, specifying supplemental inspections beyond the inspections recommended by the current BWRVIP guidelines are not necessary. The BWRVIP is chartered to review and trend operating experience from the BWR fleet relative to implementation of recommended inspections and revise the recommendations as appropriate in accordance with BWRVIP-94-R4 and NEI 03-08. As new or revised inspection recommendations are recommended by the BWRVIP, they are required to be implemented in accordance with BWRVIP-94-R4 and NEI 03-08.

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.

<u>Table 3.1.1 Item Number 3.1-1, 120:</u> This item evaluates loss of preload due to thermal or irradiation-enhanced stress relaxation in stainless steel core plate rim hold-down bolts exposed to reactor coolant with neutron flux. BFN does not currently contain core plate wedges.

The core plate rim hold-down bolts connect the core plate to the core shroud. Each of the BFN reactors has 34 core plate rim hold-down bolts. These bolts are preloaded during initial installation but are subject to stress relaxation (loss of preload) due to thermal and irradiation effects. This relaxation of preload could lead to lateral movement or sliding of the core plate under all operating conditions. 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.

The BWR Vessel Internals program (B.2.1.7) manages loss of preload due to thermal or irradiation-enhanced stress relaxation in BWR core plate rim hold-down bolts. The BWR Vessel Internals aging management program 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 hold-down bolts. Additionally, as described in the NRC Safety Evaluation Report to BWRVIP-25, plants must consider relaxation of the core plate rim hold-down bolts as a TLAA issue.

BWRVIP-25, Revision 0 required an EVT-1 examination from below the core plate, or UT from above the core plate, of 50% (17) of the hold-down bolts. If cracking was detected, the remaining 50% of the bolts were to be inspected. Unit 1 performed an EVT-1 examination from below the core plate of 50% of the rim hold-down bolts during recovery from it's extended shutdown since access below the core plate was available, but visual exams performed since the Unit 1 restart from it's extended shutdown were extremely difficult to perform because of poor accessibility and high radiation conditions with fuel in an operating reactor vessel. Visual inspections are also problematic. An EVT-1 inspection may be able to examine the unthreaded shank of a bolt. However, the threaded portion, which is theoretically more susceptible to IGSCC, is surrounded by the core plate and the core plate support ring and is hidden from view. Thus, meaningful EVT-1 exams could not be performed and, in hindsight, perhaps should not have been recommended in BWRVIP-25. Additionally, UT had significant limitations due to bolt geometry. The only feasible location for delivering acoustic energy to the bolt is through its upper end, and access to the upper end is restricted by the presence of a keeper that is fillet welded to the top of the bolt. The resulting geometry did not allow for effective wave transmission, and consequently, a Ultrasonic Test inspection was not possible.

The BWRVIP set out to generically address this issue and to develop revised guidance, which was ultimately issued in the form of BWRVIP-25 Revision 1-A , Appendix I. Until this guidance was developed and approved by the NRC, a VT-3 examination of 100% of the hold-down bolts from above the core plate was performed by TVA, in accordance with a generic deviation disposition developed by the BWRVIP and submitted by TVA to the NRC for application at BFN in the initial License Renewal Application, in order to verify that the core plate rim hold-down bolts were still performing their design function.

The stress state of these bolts was evaluated as part of the analysis performed by General Electric Hitachi (GEH) in support of EPRI's preparation of BWRVIP-25 Revision 0. The analysis determined that a 5 percent to 19 percent reduction in core plate bolt preload due to thermal and irradiation effects should be expected over the 40-year life of a plant. A subsequent generic reevaluation performed by GEH determined that the maximum relaxation value of 20% is applicable to an average fluence level of 8.0×10^{19} n/cm^2 over the length of the bolt, determined at the peak azimuthal fluence location. Since this analysis evaluated irradiation effects expected to occur in 40 years, this analysis was identified as a TLAA that required evaluation for the period of extended operation (PEO).

The evaluation of core plate bolt loss of preload was projected for 60 years of plant life, as discussed in Section 4.7.7 of the NRC Safety Evaluation Report to the BFN License Renewal Application. A plant-specific evaluation performed in support of Extended Power Uprate determined an average bolt stress relaxation of 15%, based on a fast fluence of 5×10^{19} n/cm^2 for a 60-year (54-EFPY) plant life. The plant-specific stress relaxation of 15% is bounded by the bounding value of 20% that was provided in the generic analysis in BWRVIP-25. As noted in the BFN License Renewal Application Safety Evaluation Report in response to NRC Requests for Additional Information (RAIs) and follow-up correspondence between TVA and the NRC regarding Open Item OI-4.7.7, TVA made commitments to (1) perform an additional plant-specific analysis consistent with BWRVIP-25 to demonstrate that the core plate hold-down bolts can withstand required loads, considering the effects of stress relaxation until the end of the period of extended operation, and (2) submit the analysis for NRC review two years prior to entering the period of extended operation. The evaluation was completed and documented in GEH Nuclear Energy report NEDC-33632P, Revision 0, “Browns Ferry (Units 1-3) Core Plate Bolt Analysis Stress Analysis Report,” December 2010, and was submitted to the NRC on June 15, 2011. Subsequently, the NRC issued an additional RAI letter, NRC Letter to TVA, “Browns Ferry Nuclear Plant, Units 1, 2, and 3, Request for Additional Information Related to Core Plate Bolt Stress Analysis (TAC NOS. ME6615, ME6616, and ME6617),” dated June 28, 2012. TVA and GEH responded via a letter from TVA to NRC, “Response to Request for Additional Information Regarding BWRVIP-25 Core Plate Bolt Stress Analysis for BFN Units 1, 2, and 3,” dated October 25, 2012, which included attached report NEDC-33779P Revision 1, “RAI Response Support for Core Plate Hold Down Bolt Stress Analysis Performed to Address License Renewal Commitment for Tennessee Valley Authority Browns Ferry Nuclear Plant, Units 1, 2, and 3,” dated October 2012. Also attached to this letter, in response to one of the NRC questions in their RAI letter, was the previously mentioned plant specific deviation disposition from the inspection recommendations of BWRVIP-25 Revision 0, based on the generic deviation disposition developed by the BWRVIP, “Browns Ferry Nuclear Plant Deviation Disposition Number DD-2011-01 For Deviation Disposition for Variance from BWRVIP-25 Guidance for Inspection of Core Plate Bolts.” This deviation disposition justified the performance of a VT-3 examination of 100% of the hold-down bolts from above the core plate each refueling outage, rather than performing the EVT-1 or UT exams originally recommended in BWRVIP-25 Revision 0.

On March 23, 2020, the BWRVIP received the final NRC SER for BWRVIP-25, Revision 1. BWRVIP Letter 2020-021 was distributed to the EPRI BWRVIP members on April 2, 2020, and served as notification that BWRVIP- 25, Revision 1 could be implemented subject to the requirements stated in the report, the final NRC Safety Evaluation Report, and plant-specific licensing requirements. The major difference in Revision 1 from Revision 0 is to provide a comprehensive evaluation providing justification for the elimination of periodic core plate hold-down bolt inspections, which is contained in Appendix I of the report. Upon issuance of the Safety Evaluation Report, TVA contracted Structural Integrity Associates (SIA) to prepare a Core Plate Bolt Evaluation in accordance with BWRVIP-25, Revision 1, and this evaluation provides justification for not examining the core plate bolts at BFN Units 1, 2, and 3 and closing the generic deviation disposition. BWRVIP-25, Revision 1-A was issued in September 2020, and incorporates all changes to BWRVIP-25, Revision 1 that were requested by the final NRC Safety Evaluation Report. Elimination of the requirement to perform core plate rim hold-down bolt inspections has subsequently been incorporated into the current BFN BWR Vessel Internals aging management program and the unit specific Reactor Pressure Vessel Internals Inspection (RPVII) technical instructions.

For SLR, the plant-specific core support plate rim hold-down bolt loss of preload TLAA, performed consistent with BWRVIP-25 Revision 1-A, as well as the justification for elimination of the inspection of core plate rim hold-down bolts in accordance with BWRVIP-25 Revision 1-A Appendix I has been updated (Section 4.2.9) to account for the 80 year fluence projections to the end of the subsequent period of extended operation, and shows that the generic bolt stress analysis in BWRVIP-25 Revision 1-A remains bounding for the subsequent period of extended operation and that core plate rim hold-down bolt inspections are not required for the subsequent period of extended operation because of the IGSCC resistance of the bolts, excellent BWR industry field experience, and a margin assessment on the number of bolts required to meet allowable limits.

The Peach Bottom SLRA was supplemented via Supplement 9, dated October 9, 2019, to revise Enhancement 1 to their BWR Vessel Internals Program to add specific actions to be taken for

SLR with respect to the core plate rim hold-down bolts by using BWRVIP-25, Revision 1 guidance. As noted above, the guidance provided in NRC reviewed and approved BWRVIP-25, Revision 1-A is already incorporated in the current BFN BWR Vessel Internals Program aging management program, and will continue to be followed during the subsequent period of extended operation. Therefore, the intent of Peach Bottom Supplement 9 to their SLRA is addressed in the BFN SLRA by the BFN BWR Vessel Internals program (B.2.1.7).

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.

Table 3.1.1 Item Number 3.1-1, 105: This item evaluates steel piping, piping components exposed to concrete. There are no steel piping, piping components exposed to concrete in the Reactor Vessel, the Reactor Vessel Internals System, the Reactor Vessel Vents and Drains System, or the Reactor Recirculation System.

Table 3.1.1 Item Number 3.1-1, 115: This item evaluates stainless steel piping, piping components exposed to concrete. There are no stainless steel piping, piping components exposed to concrete in the Reactor Vessel, the Reactor Vessel Internals System, the Reactor Vessel Vents and Drains System, or the Reactor Recirculation System.

3.1.2.2.16 Loss of Material Due to Pitting and Crevice Corrosion in Stainless Steel and Nickel Alloys

Loss of material due to pitting and crevice corrosion could occur in indoor or outdoor SS and nickel alloy piping, piping components, and tanks exposed to any air, condensation, or *underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components; or (d) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.*

Insulated SS and nickel alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS and nickel alloy components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific OE and the condition of SS and nickel alloy components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for SS and nickel alloy components if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion; and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel alloy piping and piping components exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage loss of material due to pitting or crevice corrosion. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

The applicant may establish that loss of material due to pitting and crevice corrosion is not an aging effect requiring management by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.

Table 3.1.1 Item Number 3.1-1, 136: This item evaluates the loss of material due to pitting and crevice corrosion in stainless steel and nickel alloy piping, piping components exposed to air and condensation. Plant-specific OE associated with stainless steel and nickel alloy piping, piping components in the Reactor Vessel, the Reactor Vessel Vents and Drains System, the Reactor recirculation System, the Reactor Core Isolation Cooling System, the High Pressure Coolant Injection System, the Residual Heat Removal System, the Core Spray System, the Standby Liquid Control System, the Sampling and Water Quality System, the Reactor Water Cleanup System, the Main Steam System, and the Reactor Feedwater System has been evaluated to determine if prolonged exposure to air-indoor uncontrolled or condensation has resulted in loss of material due to pitting or crevice corrosion. Loss of material has not been identified as an aging effect at BFN for the stainless steel and nickel alloy components in these environments, or as a result of transportable halogens, indicating that these environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in loss of material sufficient to potentially affect the intended function of an SSC.

The BFN-specific OE review revealed only one previously written Condition Report (CR) in the Corrective Action Program with the potential to represent an aging effect requiring management. This CR documented several areas on the Unit 1 reactor vessel head and flange in 2014, where pitting was found that exceeded General Electric (GE) criteria, and repairs were performed which included welding and honing. Hence, there does not appear to be an ongoing aging effect at BFN that would potentially affect the intended function of these components. Accordingly, the One-Time Inspection program (B.2.1.20) will be implemented to demonstrate that the aging effect of loss of material is not occurring in the nickel alloy and stainless steel reactor vessel penetrations, nozzles, safe ends, and welds, piping, piping components, and valve bodies exposed to air - indoor uncontrolled in the Reactor Vessel, the stainless steel and nickel alloy piping, piping components (including Reactor Coolant Pressure Boundary), hoses, heat exchanger components and valve bodies exposed to air or condensation in the Reactor Vessel Vents and Drains System, and the Reactor Recirculation System. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program.

Consistent with NUREG-2191, the One-Time Inspection program (B.2.1.20) will also be used to manage loss of material due to pitting, crevice corrosion of the stainless steel and carbon and low alloy steel piping and piping components (including Reactor Coolant Pressure Boundary), hoses, heat exchanger components and valve bodies exposed to air - indoor uncontrolled in the Reactor Core Isolation Cooling System, the High Pressure Coolant Injection System, the Residual Heat Removal System, the Core Spray System, the Standby Liquid Control System, the Sampling and Water Quality System, the Reactor Water Cleanup System, the Main Steam System, and the Reactor Feedwater System.

3.1.2.2.17 Quality Assurance for Aging Management of Nonsafety-Related Components

Quality Assurance (QA) provisions applicable to Subsequent License Renewal are discussed in Appendix A, Section A.1.4, and Appendix B, Section B.1.3.

3.1.2.2.18 Ongoing Review of Operating Experience

Ongoing review of operating experience is addressed in Appendix A, Section A.1.5, and Appendix B, Section B.1.4.

3.1.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Reactor Vessel, Internals, and Reactor Coolant System components:

- Section 4.2, Reactor Vessel and Internals Neutron Embrittlement Analyses

- Section 4.2.1.1, Reactor Vessel Neutron Fluence Analyses
- Section 4.2.1.2, Reactor Vessel Internals Neutron Fluences Analyses
- Section 4.2.2, Reactor Vessel Upper-Shelf Energy (USE) Analyses
- Section 4.2.3, Reactor Vessel Adjusted Reference Temperature (ART) Analyses
- Section 4.2.4, Reactor Vessel Pressure-Temperature (P-T) Limits
- Section 4.2.5, Reactor Vessel Circumferential Weld Failure Probability Analyses
- Section 4.2.6, Reactor Vessel Axial Weld Failure Probability Analyses
- Section 4.2.7, Reactor Vessel Reflood Thermal Shock Analysis
- Section 4.2.8, Core Shroud Reflood Thermal Shock Analysis
- Section 4.2.9, Core Plate Hold-Down Bolt Loss of Preload Analysis
- Section 4.2.10, Jet Pump Slip Joint Repair Clamp Loss of Preload Analysis
- Section 4.2.11, Jet Pump Spring Wedge Assembly Loss of Preload Analysis
- Section 4.2.12, Jet Pump Riser Repair Clamp Loss of Preload Analysis
- Section 4.2.13, Replacement Core Support Plate Extended Life Plug Irradiation-Enhanced Stress Relaxation Analysis
- Section 4.2.14, Irradiation Assisted Stress Corrosion Cracking (IASCC) of Reactor Vessel Internals
- Section 4.2.15, Core Spray Replacement Piping Bolting Loss of Preload Evaluation
- Section 4.2.16, Core Spray Sparger Repair Clamp Loss of Preload Evaluation
- Section 4.2.17, Access Hole Cover Repair Loss of Preload Evaluation
- Section 4.2.18, Jet Pump Hold-Down Beam Assembly Loss of Preload Analysis
- Section 4.2.19, Jet Pump Sensing Line Clamps Loss of Preload Analysis

- Section 4.3 Metal Fatigue Analyses
  - Section 4.3.2, Metal Fatigue of Class 1 Components
  - Section 4.3.3, Class 1 Fatigue Waivers
  - Section 4.3.5, Environmental Fatigue of Reactor Vessel and Class 1 Piping
  - Section 4.3.6, Replacement Steam Dryer Stress Report and Fatigue Evaluation
  - Section 4.3.8, Core Shroud Support Fatigue Evaluation
  - Section 4.3.9, BFN Unit 3 Core Spray T-Box Repair Fatigue Evaluation
  - Section 4.3.10, BFN Unit 3 Core Spray Lower Line Section Replacement Fatigue Evaluation
  - Section 4.3.11, Jet Pump to Core Shroud Support Plate Fatigue Evaluation
- Section 4.7, Other Plant-Specific Analyses
  - Section 4.7.3, BFN Unit 2 Reactor Vessel Axial Weld Flaw

3.1.3 Conclusion

The Reactor Vessel, Internals, and Reactor Coolant System components that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the

Reactor Vessel, Internals, and Reactor Coolant System components are identified in the summaries in Section 3.1.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the subsequent period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Reactor Vessel, Internals, and Reactor Coolant System components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the current licensing basis during the subsequent period of extended operation.

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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	Fatigue and cyclic loading are TLAAs which apply to the Reactor Vessel ; further evaluation is documented in Subsection 3.1.2.2.1.
3.1-1, 002	PWR Only				
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	Fatigue and cyclic loading are TLAAs which apply to the Reactor Vessel Internals system; further evaluation is documented in Subsection 3.1.2.2.1.
3.1-1, 004	Steel pressure vessel support skirt and attachment welds	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes	Fatigue and cyclic loading are TLAAs which apply to the Reactor Vessel; further evaluation is documented in Subsection 3.1.2.2.1.
3.1-1, 005	PWR Only				
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 toreactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	TLAA, SRP-SLR Section 4.3 "Metal Fatigue"	Yes	Fatigue and cyclic loading are TLAAs which apply to the Reactor Vessel, Reactor Recirculation, Reactor Vents and Drains, Core Spray, Residual Heat Removal, High Pressure Coolant Injection, Reactor Core Isolation Cooling, Main Steam, and Reactor Feedwater systems; further evaluation is documented in Subsection 3.1.2.2.1.

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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	Fatigue and cyclic loading are TLAAs, which apply to the Reactor Vessel and Reactor Vessel Internals systems; further evaluation is documented in Subsection 3.1.2.2.1.
3.1-1, 008	PWR Only				
3.1-1, 009	PWR Only				
3.1-1, 010	PWR Only				
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	Fatigue and cyclic loading are TLAAs, , which apply to the Reactor Vessel, Reactor Recirculation, Reactor Vessel Vents and Drains, High Pressure Coolant Injection, Reactor Core Isolation Cooling, Main Steam, and Reactor Feedwater systems; further evaluation is documented in Subsection 3.1.2.2.1.
3.1-1, 012	PWR Only				
3.1-1, 013	Steel (with or without stainless steel or nickel alloy cladding) reactor vessel beltline shell, nozzle, and weld components exposed toreactor 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	Loss of fracture toughness due to neutron embrittlement is a TLAA which applies to the Reactor Vessel; further evaluation is documented in Subsection 3.1.2.2.3.1.

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1-1, 014	Steel (with or without cladding) reactor vessel beltline shell, nozzle, and weld components; exposed to reactor coolant and neutron flux	Loss of fracture toughness due to neutron irradiation embrittlement	AMP XI.M31, “Reactor Vessel Material Surveillance,” and AMP X.M2, “Neutron Fluence Monitoring”	Yes	Consistent with NUREG-2191. The Neutron Fluence Monitoring program (B.3.1.2) and Reactor Vessel Material Surveillance program (B.2.1.19) will be used to manage loss of fracture toughness of the carbon or low alloy steel with stainless steel cladding reactor vessel shell and welds within the beltline that are exposed to reactor coolant and neutron flux in the Reactor Vessel. See Subsection 3.1.2.2.3.2.
3.1-1, 015	PWR Only				
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage cracking of the stainless steel reactor vessel flange leak detection line, reactor vessel penetrations, nozzles, safe ends and welds, and piping, piping components, and valves exposed to air - indoor uncontrolled in the Reactor Vessel. See Subsection 3.1.2.2.4.1.
3.1-1, 017	Stainless steel isolation condenser components exposed to reactor coolant	Cracking due to SCC, IGSCC	AMP XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD,” and AMP XI.M2, “Water Chemistry”	Yes	Not Applicable. The BFN BWR design does not include an isolation condenser. See Subsection 3.1.2.2.4.2.
3.1-1, 018	PWR Only				
3.1-1, 019	PWR Only				
3.1-1, 020	PWR Only				

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1-1, 021	Steel and stainless steel isolation condenser components exposed to reactor coolant	Cracking due to cyclic loading	AMP XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD”	Yes	Not Applicable. The BFN BWR design does not include an isolation condenser. See Subsection 3.1.2.2.7.
3.1-1, 022	PWR Only				
3.1-1, 023	This Item Number is not used in NUREG-2192.				
3.1-1, 024	This Item Number is not used in NUREG-2192.				
3.1-1, 025	PWR Only				
3.1-1, 026	This Item Number is not used in NUREG-2192.				
3.1-1, 027	This Item Number is not used in NUREG-2192.				
3.1-1, 028	PWR Only				
3.1-1, 029	Nickel alloy core shroudand 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	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals program (B.2.1.7) and Water Chemistry program (B.2.1.2) will be used to manage cracking of the nickel alloy core shroud and welded core plate access hole covers (two welded covers remain in Unit 3) exposed to reactor coolant and neutron flux in the Reactor Vessel Internals System, until such time as permanent bolted replacement covers are installed in Unit 3. Units 1 and 2 have bolted core plate access hole covers. See Subsection 3.1.2.2.12. Exceptions apply to the NUREG-2191 recommendations for BWR Vessel Internals program (B.2.1.7) implementation.

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
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 Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry" (SCC, IGSCC mechanisms only)	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B.2.1.1) and Water Chemistry (B.2.1.2) program will be used to manage cracking of the carbon or low alloy steel with nickel alloy cladding, carbon or low alloy steel with stainless steel cladding, nickel alloy, and stainless steel penetrations, nozzles, safe ends, welds, and vessel shell components exposed to reactor coolant and reactor coolant and neutron flux in the Reactor Vessel. The reactor vessel drain line penetration is carbon steel, therefore cracking is addressed by Item Number 3.1-1, 007.
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 Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and AMP XI.M2, "Water Chemistry"	No	Not Applicable. The BFN BWR design does not include an isolation condenser.
3.1-1, 032	PWR Only				
3.1-1, 033	PWR Only				
3.1-1, 034	PWR Only				
3.1-1, 035	PWR Only				
3.1-1, 036	PWR Only				
3.1-1, 037	PWR Only				

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1-1, 038	Cast austenitic stainless steel Class 1 valve bodies and bonnets exposed to reactor coolant >250 °C (>482 °F)	Loss of fracture toughness due to thermal aging embrittlement	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) program will be used to manage loss of fracture toughness of the cast austenitic stainless steel Class 1 valve bodies and bonnets exposed to treated water in the Reactor Vessel Vents and Drains System and treated water >482 F in the Reactor Recirculation System, the Reactor Water Cleanup System, the Residual Heat Removal System, the Core Spray System, the Sampling and Water Quality System, the Main Steam System and the Reactor Feedwater System.
3.1-1, 039	Stainless steel, steel (with or without nickel alloy or stainless steel cladding), nickel alloy Class 1 piping, fittings and branch connections < NPS 4 exposed to reactor coolant	Cracking due to SCC (for stainless steel or nickel alloy surfaces exposed to reactor coolant only), IGSCC(for stainless steel or nickel alloy surfaces exposed to reactor coolant only), or thermal, mechanical,or vibratory loading	AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," AMP XI.M2, "Water Chemistry," and XI.M35,"ASME Code Class 1 Small-Bore Piping"	No	Consistent with NUREG-2191. The ASME Code Class 1 Small-Bore Piping program (B.2.1.22), ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B.2.1.1), and Water Chemistry program (B.2.1.2) will be used to manage cracking of the steel (with or without nickel alloy or stainless steel cladding), carbon steel and stainless steel Class 1 piping, fittings, and branch connections less than 4" NPS and greater than or equal to 1" NPS exposed to reactor coolant, steam, treated water, and treated water > 140 F in the Reactor Vessel, the Reactor Recirculation System, the Reactor Core Isolation Cooling System, the High Pressure Coolant Injection System, the Residual Heat Removal System, the Core Spray System, the Standby Liquid Control System, the Reactor Water Cleanup System, the Main Steam System, and the Reactor Feedwater System.
3.1-1, 040	PWR Only				
3.1-1, 040a	PWR Only				

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1-1, 041	Nickel alloy core shroudand 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	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals program (B.2.1.7) and the Water Chemistry program (B.2.1.2) will be used to manage cracking of the nickel alloy core shroud and the X-750 alloy core plate access hole covers (mechanical) exposed to reactor coolant in the Reactor Vessel Internals System. Units 1 and 2 have bolted core plate access hole covers. There are plans to install permanent bolted replacement covers on both core plate access holes in Unit 3 during a future refueling outage. See Subsection 3.1.2.2.12. Exceptions apply to the NUREG-2191 recommendations for BWR Vessel Internals program (B.2.1.7) implementation.
3.1-1, 042	PWR Only				
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 Section XI Inservice Inspection, Subsections IWB, IWC, and IWD,” and AMP XI.M2, “Water Chemistry”	No	The BWR Vessel Internals program (B.2.1.7) has been substituted for the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B.2.1.1), and will be used with the Water Chemistry program (B.2.1.2) to manage loss of material of Stainless Steel, Stainless Steel bolting, Nickel alloy, X-750 alloy, and CASS reactor vessel internal components exposed to reactor coolant, and reactor coolant and neutron flux in the Reactor Vessel Internals System. Exceptions apply to the NUREG-2191 recommendations for BWR Vessel Internals program (B.2.1.7) implementation.
3.1-1, 044	PWR Only				
3.1-1, 045	PWR Only				
3.1-1, 046	PWR Only				

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1-1, 047	PWR Only				
3.1-1, 048	PWR Only				
3.1-1, 049	PWR Only				
3.1-1, 050	Cast austenitic stainlesssteel Class 1 piping, piping components (including pump casingsand 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. The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program (.2.1.8) will be used to manage loss of fracture toughness of the cast austenitic stainless steel Class 1 Reactor Recirculation pump casings exposed to treated water >482 F in the Reactor Recirculation System, and the Class 1 piping, and piping components in the Main Steam System.
3.1-1, 051a	PWR Only				
3.1-1, 051b	PWR Only				
3.1-1, 052a	PWR Only				
3.1-1, 052b	PWR Only				
3.1-1, 052c	PWR Only				
3.1-1, 053a	PWR Only				
3.1-1, 053b	PWR Only				
3.1-1, 053c	PWR Only				
3.1-1, 054	PWR Only				
3.1-1, 055a	PWR Only				
3.1-1, 055b	PWR Only				

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1-1, 055c	PWR Only				
3.1-1, 056a	PWR Only				
3.1-1, 056b	PWR Only				
3.1-1, 056c	PWR Only				
3.1-1, 057	This Item Number is not used in NUREG-2192.				
3.1-1, 058a	PWR Only				
3.1-1, 058b	PWR Only				
3.1-1, 059a	PWR Only				
3.1-1, 059b	PWR Only				
3.1-1, 059c	PWR Only				
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	Consistent with NUREG-2191. The Flow-Accelerated Corrosion program (B.2.1.9) will be used to manage wall thinning of the carbon steel piping, piping components exposed to reactor coolant, and treated water in the Reactor Vessel, the Reactor Recirculation System, the Reactor Core Isolation Cooling System, the High Pressure Coolant Injection System, The Reactor Water Cleanup System, the Main Steam System, and the Reactor Feedwater System.
3.1-1, 061	PWR Only				

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1-1, 062	High-strength steel, stainless steel closure bolting; stainless steel control rod drive head penetration flange boltingexposed to air-indoor uncontrolled	Cracking due to SCC	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity program (B.2.1.10) will be used to manage cracking of the high strength steel, carbon and low allow steel, and stainless steel closure bolting exposed to air - indoor uncontrolled in the Reactor Vessel, the Reactor Vessel Vents and Drains System, the Reactor Recirculation System, the Main Steam System, and the Reactor Feedwater System.
3.1-1, 063	Steel or stainless steel closure bolting exposed to air – indoor uncontrolled	Loss of material due to general (steel only), pitting, crevicecorrosion, wear	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity program (B.2.1.10) will be used to manage loss of material of the steel, stainless steel, carbon and low alloy steel, and high strength low alloy steel, closure bolting exposed to air - indoor uncontrolled in the Reactor Vessel, the Reactor Vessel Vents and Drains System, the Reactor Recirculation System, the Reactor Core Isolation Cooling System, the Main Steam System, and the Reactor Feedwater System.
3.1-1, 064	PWR Only				
3.1-1, 065	PWR Only				
3.1-1, 066	PWR Only				

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.1-1, 067	Steel or stainless steel closure bolting exposedto air – indoor uncontrolled (external)	Loss of preload due to thermal effects, gasket creep, self- loosening	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity program (B.2.1.10) will be used to manage loss of preload of steel, stainless steel, carbon and low alloy steel, and high strength low alloy steel closure bolting exposed to air - indoor uncontrolled in the Reactor Vessel, the Reactor Vessel Vents and Drains System, the Reactor Recirculation System, the High Pressure Coolant Injection System, the Reactor Core Isolation Cooling System, the Main Steam System, and the Reactor Feedwater System.
3.1-1, 068	PWR Only				
3.1-1, 069	PWR Only				
3.1-1, 070	PWR Only				
3.1-1, 071	PWR Only				
3.1-1, 072	PWR Only				
3.1-1, 073	PWR Only				
3.1-1, 074	PWR Only				
3.1-1, 075	PWR Only				
3.1-1, 076	PWR Only				
3.1-1, 077	PWR Only				
3.1-1, 078	PWR Only				

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) and Water Chemistry program (B.2.1.2) will be used to manage loss of material due to pitting, crevice corrosion of carbon and low alloy steel, and stainless steel Class 1 piping and piping components, and Class 1 valve bodies, and CASS Recirculation Pump casings and Class 1 valve bodies exposed to treated water or reactor coolant in the Reactor Vessel, the Reactor Vessel Vents and Drains System, the Reactor Recirculation System, the Sampling and Water Quality System, the Standby Liquid Control System, the Reactor Water Cleanup System, the Reactor Core Isolation Cooling System, the High Pressure Coolant Injection System, the Residual Heat Removal System, the Core Spray System, the Main Steam System and the Reactor Feedwater System.
3.1-1, 080	PWR Only				
3.1-1, 081	PWR Only				
3.1-1, 082	PWR Only				
3.1-1, 083	PWR Only				

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) and Water Chemistry program (B.2.1.2) will be used to manage loss of material due to general, pitting, crevice corrosion of carbon steel reactor vessel upper head, reactor vessel nozzles, safe-ends, welds, and vessel internal attached components exposed to reactor coolant in the Reactor Pressure Vessel and Reactor Vessel Internals Systems.
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) and Water Chemistry program (B.2.1.2) will be used to manage loss of material due to pitting, crevice corrosion of the carbon or low alloy steel with nickel alloy cladding, carbon or low alloy steel with stainless steel cladding, nickel alloy, and stainless steel reactor vessel flanges, nozzles, safe ends, vessel shells, heads, vessel internal attached components, and welds exposed to reactor coolant and reactor coolant with neutron flux in the Reactor Pressure Vessel and Reactor Vessel Internals Systems.
3.1-1, 086	PWR Only				
3.1-1, 087	PWR Only				
3.1-1, 088	PWR Only				
3.1-1, 089	PWR Only				
3.1-1, 090	PWR Only				

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
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	Consistent with NUREG-2191 with exceptions. The Reactor Head Closure Stud Bolting program (B.2.1.3) will be used to manage cracking due to SCC and loss of material due to general, pitting, crevice corrosion, and wear of the high strength low alloy steel bolting with yield strength of 150 ksi or greater reactor vessel closure flange assembly components exposed to air - indoor uncontrolled in the Reactor Vessel. Exceptions apply to the NUREG-2191 recommendations for Reactor Head Closure Stud Bolting program (B.2.1.3) implementation.
3.1-1, 092	PWR Only				
3.1-1, 093	PWR Only				
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	Consistent with NUREG-2191 with exceptions. The BWR Vessel ID Attachment Welds program (B.2.1.4) and Water Chemistry program (B.2.1.2) will be used to manage cracking due to SCC, IGSCC, cyclic loading of the stainless steel reactor vessel internal attachedcomponents exposed to reactor coolant, and reactor coolant and neutron flux in the Reactor Vessel and Internals System. Exceptions apply to the NUREG-2191 recommendations for BWR Vessel ID Attachment Welds program (B.2.1.4) implementation.

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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 Section XI Inservice Inspection, Subsections IWB, IWC, and IWD”	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B.2.1.1) will be used to manage cracking due to cyclic loading of the carbon steel reactor vessel feedwater nozzles exposed to reactor coolant and the carbon or low alloy steel with stainless steel cladding reactor vessel shell and welds exposed to reactor coolant and neutron flux in the Reactor Vessel.
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 Section XI Inservice Inspection, Subsections IWB, IWC, and IWD”	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B.2.1.1) will be used to manage cracking of the capped carbon or low alloy steel with stainless steel cladding reactor vessel control rod drive return line nozzle exposed to reactor coolant in the Reactor Vessel.

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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	Consistent with NUREG-2191 with exceptions. The BWR Stress Corrosion Cracking program (B.2.1.5) and Water Chemistry program (B.2.1.2) will be used to manage cracking due to SCC, IGSCC of the Class 1 stainless steel piping and piping components exposed to treated water, stainless steel piping, piping components greater than or equal to 4 inches NPS exposed to treated water >93°C [>200°F] (Internal) and reactor coolant, and reactor vessel CRD return line nozzle safe ends, cap and associated welds exposed to reactor coolant in the Reactor Vessel, the Reactor Vessel Vents and Drains System, the Reactor Recirculation System, the Reactor Core Isolation Cooling System, the Residual Heat Removal System, the Core Spray System, the Reactor Water Cleanup System, the Sampling and Water Quality System, the Main Steam System, and the Reactor Feedwater System. Exceptions apply to the NUREG-2191 recommendations for BWR Stress Corrosion Cracking program (B.2.1.5) implementation.

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191 with exceptions. The BWR Penetrations program (B.2.1.6) and Water Chemistry program (B.2.1.2) will be used to manage cracking due to SCC, IGSCC, cyclic loading of the carbon or low alloy steel with stainless steel cladding, nickel alloy, and stainless steel core plate d/p and SLC nozzle, and reactor vessel instrumentation penetrations and nozzles, and penetrations for control rod drive stub tubes, in core monitor housings, jet pump instruments standby liquid control, and neutron flux monitors exposed to reactor coolant and reactor coolant and neutron flux in the Reactor Vessel. Exceptions apply to the NUREG-2191 recommendations for BWR Penetrations program (B.2.1.6) implementation.
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 irradiationembrittlement	AMP XI.M9, “BWR Vessel Internals”	Yes	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals program (B.2.1.7) will be used to manage loss of fracture toughness due to thermal aging, neutron irradiation embrittlement of the cast austenitic stainless steel, nickel alloy, and stainless steel reactor vessel internal components exposed to reactor coolant and neutron flux in the Reactor Vessel and Reactor Vessel Internals Systems. See Subsection 3.1.2.2.13. Exceptions apply to the NUREG-2191 recommendations for BWR Vessel Internals program (B.2.1.7) implementation.

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
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	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals program (B.2.1.7) will be used to manage loss of material due to wear of the stainless steel jet pump assemblies: thermal sleeve, inlet header, riser brace arm, hold- down beams, and wedges exposed to reactor coolant and neutron flux in the Reactor Vessel Internals System. Exceptions apply to the NUREG-2191 recommendations for BWR Vessel Internals program (B.2.1.7) implementation.
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	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals program (B.2.1.7) will be used to manage cracking due to flow-induced vibration, SCC, IGSCC and loss of material due to wear of the stainless steel reactor vessel internals components: steam dryers exposed to reactor coolant in the Reactor Vessel Internals System. Exceptions apply to the NUREG-2191 recommendations for BWR Vessel Internals program (B.2.1.7) implementation.

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals program (B.2.1.7) and Water Chemistry program (B.2.1.2) will be used to manage cracking due to SCC, IGSCC of the stainless steel CRD Housings exposed to reactor coolant, CASS and stainless steel fuel supports and control rod drive assemblies exposed to reactor coolant and neutron flux in the Reactor Vessel Internals System. Exceptions apply to the NUREG-2191 recommendations for BWR Vessel Internals program (B.2.1.7) implementation.
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	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals program (B.2.1.7) and Water Chemistry program (B.2.1.2) will be used to manage cracking due to SCC, IGSCC, and irradiation-assisted SCC of the stainless steel bolting, nickel alloy, X-750 alloy, CASS, and stainless steel reactor vessel nozzle components and reactor vessel internal components exposed to reactor coolant and reactor coolant and neutron flux in the Reactor Vessel and Reactor Vessel Internals Systems. See Subsection 3.1.2.2.12. Exceptions apply to the NUREG-2191 recommendations for BWR Vessel Internals program (B.2.1.7) implementation.

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals program (B.2.1.7) and Water Chemistry program (B.2.1.2) will be used to manage cracking due to IGSCC of the nickel alloy and X-750 alloy reactor vessel internals components exposed to reactor coolant and neutron flux in the Reactor Vessel Internals System. Exceptions apply to the NUREG-2191 recommendations for BWR Vessel Internals program (B.2.1.7) implementation.
3.1-1, 105	Steel piping, piping components exposed to concrete	None	None	Yes	Not Applicable. There are no steel piping, piping components exposed to concrete in the Reactor Vessel, Reactor Vessel Internals, Reactor Vessel Vents and Drains, and Reactor Recirculation Systems. See Subsection 3.1.2.2.15.
3.1-1, 106	Nickel alloy piping, piping components exposed to air with borated water leakage	None	None	No	Not Applicable. There are no nickel alloy piping, piping components exposed to air with borated water leakage in the Reactor Vessel, Reactor Vessel Internals, Reactor Vessel Vents and Drains, and Reactor Recirculation Systems.
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, 108	This Item Number is not used in NUREG-2192.				

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1-1, 109	This Item Number is not used in NUREG-2192.				
3.1-1, 110	Metallic piping, piping components exposed to reactor coolant	Wall thinning due to erosion	AMP XI.M17, “Flow-Accelerated Corrosion”	No	Consistent with NUREG-2191. The Flow-Accelerated Corrosion program (B.2.1.9) will be used to manage wall thinning due to erosion of the steel and stainless steel exposed to reactor coolant in the High Pressure Coolant Injection System, the Main Steam System, the Reactor Feedwater System, and the carbon and low alloy steel Class 1 piping, piping components, and valve bodies exposed to treated water in the Reactor Vessel Vents and Drains System.
3.1-1, 111	PWR Only				
3.1-1, 112	This Item Number is not used in NUREG-2192.				
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 Section XI Inservice Inspection, Subsections IWB, IWC, and IWD”	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B.2.1.1) will be used to manage loss of material due to general, pitting, crevice corrosion, and wear of the carbon steel reactor vessel external attachments, support skirt, and welds exposed to air - indoor uncontrolled in the Reactor Vessel.

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1-1, 114	Reactor coolant system components defined as ASME Section XI Code Class components (ASME Code Class 1 reactor coolant pressure boundary components or core support structure components, or ASME Class 2 or 3 components - including ASME defined appurtenances, component supports, and associated pressure boundary welds, or components subject to plant-specific equivalent classifications for these ASME code classes)	Cracking due to SCC, IGSCC (stainless steel, nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	AMP XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD,” and AMP XI.M2, “Water Chemistry” (water chemistry-related or corrosion-related aging effect mechanisms only)	No	Consistent with NUREG-2191. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B.2.1.1) and Water Chemistry program (B.2.1.2) will be used to manage cracking and loss of material of the steel. Stainless steel, carbon or low alloy steel with nickel alloy cladding, carbon or low alloy steel with stainless steel cladding, CASS, and stainless steel reactor coolant components defined as ASME Section XI Code Class components exposed to air, condensation, reactor coolant, threated water, or treated water > 140 F in the Reactor Vessel, the Reactor Recirculation System, the Reactor Core Isolation Cooling System, the High Pressure Coolant Injection System, the Residual Heat Removal System, the Core Spray System, the Sampling and Water Quality System, the Main Steam System, and the Reactor Feedwater System.
3.1-1, 115	Stainless steel piping, piping components exposed to concrete	None	None	Yes	Not Applicable. There are no stainless steel piping, piping components exposed to concrete in the Reactor Vessel, Reactor Vessel Internals, Reactor Vessel Vents and Drains, and Reactor Recirculation Systems. See Subsection 3.1.2.2.15.
3.1-1, 116	PWR Only				
3.1-1, 117	PWR Only				
3.1-1, 118	PWR Only				
3.1-1, 119	PWR Only				

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals program (B.2.1.7) and TLAA will be used to manage loss of preload due to thermal or irradiation-enhanced stress relaxation of the stainless steel core plate rim holddown bolts exposed to reactor coolant and neutron flux in the Reactor Vessel Internals System. Exceptions apply to the NUREG-2191 recommendations for BWR Vessel Internals program (B.2.1.7) implementation. Loss of preload is a TLAA; further evaluation is documented in Subsection 3.1.2.2.14.
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	Consistent with NUREG-2191 with exceptions. The BWR Vessel Internals program (B.2.1.7) will be used to manage loss of preload due to thermal or irradiation-enhanced stress relaxation of the stainless steel jet pump assembly holddown beam bolts exposed to reactor coolant and neutron flux in the Reactor Vessel Internals System. Exceptions apply to the NUREG-2191 recommendations for BWR Vessel Internals program (B.2.1.7) implementation.
3.1-1, 122	This Item Number is not used in NUREG-2192.				
3.1-1, 123	This Item Number is not used in NUREG-2192.				

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1-1, 124	Steel piping, piping components exposed to air-indoor uncontrolled, air-outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage loss of material due to general, pitting, and crevice corrosion of the steel, carbon steel, stainless steel, CASS, and carbon and low alloy steel piping, piping components, and valve bodies exposed to air - indoor uncontrolled in the Reactor Water Cleanup System, the Reactor Vessel and Reactor Vessel Vents and Drains System, the Reactor Recirculation System, the Reactor Core Isolation Cooling System, the High Pressure Coolant Injection System, the Residual Heat Removal System, the Core Spray System, the Reactor Feedwater System, and the Main Steam System. The aging effect of loss of material due to general corrosion does not apply to the carbon steel external surfaces of reactor vessel, nozzle, and safe end components exposed to air - indoor uncontrolled in the Reactor Vessel. During power operation the insulated reactor vessel, nozzles, and safe end components have an external temperature greater than 212 °F and are at a higher temperature than the air - indoor uncontrolled environment. During plant shutdown the reactor vessel components and containment atmosphere temperatures are normally above the dewpoint temperature. Therefore, wetting due to condensation and moisture accumulation will not occur during power operation or plant shutdown and loss of material due to general, pitting, or crevice corrosion does not apply.

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1-1, 125	PWR Only				
3.1-1, 126	This Item Number is not used in NUREG-2192.				
3.1-1, 127	PWR Only				
3.1-1, 128	Stainless steel, nickel alloy nozzles safe ends and welds: high pressurecore 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	Consistent with NUREG-2191 with exceptions. The BWR Stress Corrosion Cracking program (B.2.1.5) and Water Chemistry program (B.2.1.2) will be used to manage cracking due to SCC, or IGSCC of the nickel alloy and stainless steel reactor vessel nozzle safe ends and welds exposed to reactor coolant in the Reactor Vessel. Exceptions apply to the NUREG-2191 recommendations for BWR Stress Corrosion Cracking program (B.2.1.5) implementation.
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 Section XI Inservice Inspection, Subsections IWB, IWC, and IWD”	No	Not Applicable. The BFN design does not include re-routed control rod drive returnlines to the reactor vessel. The original control rod drive return lines have been capped at the reactor vessel nozzle. Control rod drive flow is returned to the reactor vessel though the control rod drive cooling water lines.
3.1-1, 130	This Item Number is not used in NUREG-2192.				
3.1-1, 131	This Item Number is not used in NUREG-2192.				
3.1-1, 132	This Item Number is not used in NUREG-2192.				

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage long-term loss of material due to general corrosion of the carbon steel reactor vessel upper head, reactor vessel nozzles, safe ends, and welds, piping, piping components, valve bodies, and reactor vessel internal components exposed to reactor coolant and treated water, in the Reactor Vessel, Reactor Vessel Internals, and Reactor Recirculation Systems, as well as carbon and low alloy steel, CASS, and stainless steel piping, piping components, and valve bodies exposed to treated water in the Reactor Vessel Vents and Drains System, and steel piping and piping components exposed to treated water in the Reactor Core Isolation Cooling, High Pressure Coolant Injection, Residual Heat Removal, Core Spray, Main Steam, and Reactor Feedwater Systems.
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. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage reduced thermal insulation resistance due to moisture intrusion for non-metallic thermal insulation exposed to air – indoor uncontrolled, as shown in Table 3.5.2-36, Structural Commodities (Thermal Insulation), in the Main Steam System and the Reactor Feedwater System.
3.1-1, 135	This Item Number is not used in NUREG-2192.				

Table 3.1.1, Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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	Consistent with NUREG-2191, the One-Time Inspection program (B.2.1.20) will be used to manage loss of material due to pitting, crevice corrosion of the nickel alloy and stainless steel reactor vessel penetrations, nozzles, safe ends, and welds, piping, piping components, and valve bodies exposed to air - indoor uncontrolled in the Reactor Vessel. Consistent with NUREG-2191, the One-Time Inspection program (B.2.1.20) will be used to manage loss of material due to pitting, crevice corrosion of the stainless steel and carbon and low alloy steel piping and piping components (including Reactor Coolant Pressure Boundary), hoses, heat exchanger components and valve bodies exposed to air - indoor uncontrolled in the Reactor Vessel Vents and Drains System, the Reactor Recirculation System, the Reactor Core Isolation Cooling System, the High Pressure Coolant Injection System, the Residual Heat Removal System, the Core Spray System, the Standby Liquid Control System, the Sampling and Water Quality System, the Reactor Water Cleanup System, the Main Steam System, and the Reactor Feedwater System. See Subsection 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 for the Reactor Recirculation and Reactor Feedwater systems.
3.1-1, 138	This Item Number is not used in NUREG-2192.				
3.1-1, 139	PWR Only				

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Class 1)	Mechanical Closure	Steel	Air - Indoor Uncontrolled (External)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.RP-44	3.1-1, 011	A
Bolting (Class 1)	Mechanical Closure	High-strength steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC	Bolting Integrity (B.2.1.10)	IV.C1.R-11	3.1-1, 062	A
Bolting (Class 1)	Mechanical Closure	Steel	Air - Indoor Uncontrolled (External)	Loss of material due to general (steel only), pitting, crevice corrosion, wear	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1-1, 063	A
Bolting (Class 1)	Mechanical Closure	High-strength steel	Air - Indoor Uncontrolled (External)	Loss of material due to general (steel only), pitting, crevice corrosion, wear	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1-1, 063	A
Bolting (Class 1)	Mechanical Closure	Steel	Air - Indoor Uncontrolled (External)	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1-1, 067	A
Bolting (Class 1)	Mechanical Closure	High-strength steel	Air - Indoor Uncontrolled (External)	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1-1, 067	A
Bolting (Closure)	Mechanical Closure	Steel	Air - Indoor Uncontrolled (External)	Loss of material due to general (steel only), pitting, crevice corrosion, wear	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1-1, 063	A
Bolting (Closure)	Mechanical Closure	Steel	Air - Indoor Uncontrolled (External)	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1-1, 067	A
Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC, IGSCC	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1-1, 016	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Flow Device	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC, IGSCC	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1-1, 016	A
Flow Device	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1-1, 114	A
Flow Device	Throttle	Stainless Steel	Condensation (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1-1, 114	A
Flow Device	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flow Device	Throttle	Stainless Steel	Condensation (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Flow Device	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Flow Device	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A
Flow Device	Throttle	Stainless Steel	Condensation (Internal)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Steel	Reactor Coolant (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Steel	Reactor Coolant (Internal)	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), thermal, mechanical, vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1-1, 039	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Steel	Reactor Coolant (Internal)	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), thermal, mechanical, vibratory loading	Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1-1, 039	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Steel	Reactor Coolant (Internal)	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), thermal, mechanical, vibratory loading	ASME Code Class 1 Small-Bore Piping (B.2.1.22)	IV.C1.RP-230	3.1-1, 039	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	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), thermal, mechanical, vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1-1, 039	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	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), thermal, mechanical, vibratory loading	Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1-1, 039	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	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), thermal, mechanical, vibratory loading	ASME Code Class 1 Small-Bore Piping (B.2.1.22)	IV.C1.RP-230	3.1-1, 039	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Steel	Reactor Coolant (Internal)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-23	3.1-1, 060	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1-1, 079	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Steel	Air - Indoor Uncontrolled (External)	Long-term loss of material due to general corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Steel	Reactor Coolant (Internal)	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.A1.R-448	3.1-1, 133	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2-1, 016	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	V.D2.EP-60	3.2-1, 016	A
Reactor Vessel (Bottom Head and Welds)	Pressure Boundary	Steel with Nickel Alloy Cladding	Reactor Coolant (Internal)	Cumulative Fatigue Damage	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
Reactor Vessel (Bottom Head and Welds)	Pressure Boundary	Steel with Nickel Alloy Cladding	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC, cyclic loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.A1.RP-371	3.1-1, 030	C
Reactor Vessel (Bottom Head and Welds)	Pressure Boundary	Steel with Nickel Alloy Cladding	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC, cyclic loading	Water Chemistry (B.2.1.2) (SCC, IGSCC mechanisms only)	IV.A1.RP-371	3.1-1, 030	C

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Reactor Vessel (Bottom Head and Welds)	Pressure Boundary	Steel with Nickel Alloy Cladding	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
Reactor Vessel (Bottom Head and Welds)	Pressure Boundary	Steel with Nickel Alloy Cladding	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
Reactor Vessel (Bottom Head and Welds)	Pressure Boundary	Steel with Nickel Alloy Cladding	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1-1, 124	I, 2
Reactor Vessel Closure Flange Assembly Components	Mechanical Closure	High-strength steel	Air - Indoor Uncontrolled (External)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.A1.RP-201	3.1-1, 001	A
Reactor Vessel Closure Flange Assembly Components	Pressure Boundary	Steel with Nickel Alloy Cladding	Reactor Coolant (Internal)	Cumulative Fatigue Damage	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
Reactor Vessel Closure Flange Assembly Components	Pressure Boundary	Steel with Nickel Alloy Cladding	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
Reactor Vessel Closure Flange Assembly Components	Pressure Boundary	Steel with Nickel Alloy Cladding	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
Reactor Vessel Closure Flange Assembly Components	Mechanical Closure	High-strength steel	Air - Indoor Uncontrolled (External)	Loss of material due to general, pitting, crevice corrosion, wear	Reactor Head Closure Stud Bolting (B.2.1.3)	IV.A1.RP-165	3.1-1, 091	B
Reactor Vessel Closure Flange Assembly Components	Mechanical Closure	High-strength steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC, IGSCC	Reactor Head Closure Stud Bolting (B.2.1.3)	IV.A1.RP-51	3.1-1, 091	B

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel Closure Flange Assembly Components	Pressure Boundary	Steel with Nickel Alloy Cladding	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1-1, 114	A
Reactor Vessel Closure Flange Assembly Components	Pressure Boundary	Steel with Nickel Alloy Cladding	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
Reactor Vessel Closure Flange Assembly Components	Pressure Boundary	Steel with Nickel Alloy Cladding	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1-1, 124	I, 2
Reactor Vessel External Attachments, Support Skirt, Stabilizer Bracket, and Welds	Structural Support	Steel	Air - Indoor Uncontrolled (External)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.A1.R-70	3.1-1, 004	A
Reactor Vessel External Attachments, Support Skirt, Stabilizer Bracket, and Welds	Structural Support	Steel	Air - Indoor Uncontrolled (External)	Loss of material due to general, pitting, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.A1.R-409	3.1-1, 113	A
Reactor Vessel Flange Leak Detection Line	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC, IGSCC	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1-1, 016	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel Flange Leak Detection Line	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1-1, 114	A
Reactor Vessel Flange Leak Detection Line	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
Reactor Vessel Flange Leak Detection Line	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Reactor Vessel Flange Leak Detection Line	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC, IGSCC	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1-1, 016	C
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.A1.RP-157	3.1-1, 085	E, 1
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Direct Flow	Stainless Steel	Reactor Coolant	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Direct Flow	Stainless Steel	Reactor Coolant	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.A1.RP-157	3.1-1, 085	E, 1

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.A1.RP-157	3.1-1, 085	E, 1
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.A1.RP-157	3.1-1, 085	E, 1
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant	Cracking due to SCC, IGSCC, cyclic loading	Water Chemistry (B.2.1.2) (SCC, IGSCC mechanisms only)	IV.A1.RP-369	3.1-1, 098	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant	Cracking due to SCC, IGSCC, cyclic loading	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1-1, 098	B
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Direct Flow	Stainless Steel	Reactor Coolant	Cracking due to SCC, IGSCC, cyclic loading	Water Chemistry (B.2.1.2) (SCC, IGSCC mechanisms only)	IV.A1.RP-369	3.1-1, 098	A
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Direct Flow	Stainless Steel	Reactor Coolant	Cracking due to SCC, IGSCC, cyclic loading	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1-1, 098	B
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC, cyclic loading	Water Chemistry (B.2.1.2) (SCC, IGSCC mechanisms only)	IV.A1.RP-369	3.1-1, 098	A
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC, cyclic loading	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1-1, 098	B

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, cyclic loading	Water Chemistry (B.2.1.2) (SCC, IGSCC mechanisms only)	IV.A1.RP-369	3.1-1, 098	A
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, cyclic loading	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1-1, 098	B
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of fracture toughness due to neutron irradiation embrittlement	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-200	3.1-1, 099	B
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-422	3.1-1, 103	A
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-422	3.1-1, 103	B

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel Penetrations: control rod drive stub tubes; in core monitor housings; jet pump instrument; standby liquid control; flux monitor	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	C
Reactor Vessel (Shell and Welds)	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant and Neutron Flux (Internal)	Cumulative Fatigue Damage	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
Reactor Vessel (Shell and Welds)	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant and Neutron Flux (Internal)	Loss of fracture toughness due to neutron irradiation embrittlement	Section 4.2 “Reactor Vessel and Internals Neutron Embrittlement”	IV.A1.R-62	3.1-1, 013	A, 3
Reactor Vessel (Shell and Welds)	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant and Neutron Flux (Internal)	Loss of fracture toughness due to neutron irradiation embrittlement	Neutron Fluence Monitoring (B.3.1.2)	IV.A1.RP-227	3.1-1, 014	A, 3
Reactor Vessel (Shell and Welds)	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant and Neutron Flux (Internal)	Loss of fracture toughness due to neutron irradiation embrittlement	Reactor Vessel Material Surveillance (B.2.1.19)	IV.A1.RP-227	3.1-1, 014	A, 3
Reactor Vessel (Shell and Welds)	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant and Neutron Flux (Internal)	Cracking due to SCC, IGSCC, cyclic loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.A1.RP-371	3.1-1, 030	C
Reactor Vessel (Shell and Welds)	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant and Neutron Flux (Internal)	Cracking due to SCC, IGSCC, cyclic loading	Water Chemistry (B.2.1.2) (SCC, IGSCC mechanisms only)	IV.A1.RP-371	3.1-1, 030	C

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Reactor Vessel (Shell and Welds)	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant and Neutron Flux (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
Reactor Vessel (Shell and Welds)	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant and Neutron Flux (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
Reactor Vessel (Shell and Welds)	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant and Neutron Flux (Internal)	Cracking due to cyclic loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.A1.R-65	3.1-1, 095	C, E
Reactor Vessel (Shell and Welds)	Pressure Boundary	Steel with Stainless Steel Cladding	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1-1, 124	I, 2
Reactor Vessel (Upper Head)	Pressure Boundary	Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
Reactor Vessel (Upper Head)	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1-1, 084	A
Reactor Vessel (Upper Head)	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-50	3.1-1, 084	A
Reactor Vessel (Upper Head)	Pressure Boundary	Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1-1, 124	I, 2
Reactor Vessel (Upper Head)	Pressure Boundary	Steel	Reactor Coolant (Internal)	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.A1.R-448	3.1-1, 133	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Piping, Piping Components (Valve Body)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC, IGSCC	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1-1, 016	A
Piping, Piping Components (Valve Body)	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1-1, 114	A
Piping, Piping Components (Valve Body)	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
Piping, Piping Components (Valve Body)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Piping, Piping Components (Valve Body)	Pressure Boundary	Stainless Steel	Condensation (Internal)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Steel	Reactor Coolant (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1-1, 079	A
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	A
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1-1, 114	A
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Steel	Air - Indoor Uncontrolled (External)	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Steel	Reactor Coolant (Internal)	Long-Term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1-1, 133	A
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2-1, 016	A
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	V.D2.EP-60	3.2-1, 016	A
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1-1, 114	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1-1, 124	I, 2
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC, IGSCC	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1-1, 016	C
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC	Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1-1, 128	A
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1-1, 128	B
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC	Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1-1, 128	A
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1-1, 128	B
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
(N-1A/B Recirc Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1-1, 114	A
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1-1, 124	I, 2
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC, IGSCC	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1-1, 016	C
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC	Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1-1, 128	A
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1-1, 128	B
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC	Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1-1, 128	A
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1-1, 128	B
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1-1, 103	A
(N-2A-K Recirc Inlet) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1-1, 103	B
(N-3A-D Steam Outlet) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N-3A-D Steam Outlet) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
(N-3A-D Steam Outlet) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
(N-3A-D Steam Outlet) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1-1, 114	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-3A-D Steam Outlet) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
(N-3A-D Steam Outlet) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1-1, 124	I, 2
(N-3A-D Steam Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Reactor Coolant (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N-3A-D Steam Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1-1, 084	C
(N-3A-D Steam Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-50	3.1-1, 084	C
(N-3A-D Steam Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1-1, 124	I, 2
(N-3A-D Steam Outlet) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Reactor Coolant (Internal)	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.A1.R-448	3.1-1, 133	A
(N-4A-F Feedwater) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-4A-F Feedwater) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1-1, 084	C
(N-4A-F Feedwater) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-50	3.1-1, 084	C
(N-4A-F Feedwater) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Cracking due to cyclic loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.A1.R-65	3.1-1, 095	A
(N-4A-F Feedwater) Reactor Vessel Nozzle	Pressure Boundary	Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1-1, 124	I, 2
(N-4A-F Feedwater) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.A1.R-448	3.1-1, 133	A
(N-4A-F Feedwater) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Reactor Coolant (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N-4A-F Feedwater) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1-1, 084	C
(N-4A-F Feedwater) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-50	3.1-1, 084	C
(N-4A-F Feedwater) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1-1, 124	I, 2
(N-4A-F Feedwater) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Reactor Coolant (Internal)	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.A1.R-448	3.1-1, 133	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-4A-F Feedwater) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N-4A-F Feedwater) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
(N-4A-F Feedwater) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
(N-4A-F Feedwater) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1-1, 103	C
(N-4A-F Feedwater) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1-1, 103	D
(N-5A/B Core Spray) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N-5A/B Core Spray) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
(N-5A/B Core Spray) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-5A/B Core Spray) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1-1, 114	A
(N-5A/B Core Spray) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
(N-5A/B Core Spray) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1-1, 124	I, 2
(N-5A/B Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N-5A/B Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N-5A/B Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC, IGSCC	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1-1, 016	C
(N-5A/B Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
(N-5A/B Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
(N-5A/B Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
(N-5A/B Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
(N-5A/B Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC	Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1-1, 128	A
(N-5A/B Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1-1, 128	B
(N-5A/B Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC	Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1-1, 128	A
(N-5A/B Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1-1, 128	B
(N-5A/B Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Nickel Alloy	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
(N-5A/B Core Spray) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
(N-5A/B Core Spray) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant	Cumulative Fatigue Damage	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-5A/B Core Spray) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
(N-5A/B Core Spray) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
(N-5A/B Core Spray) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-99	3.1-1, 103	A
(N-5A/B Core Spray) Reactor Vessel Nozzle, Thermal Sleeves	Direct Flow	Stainless Steel	Reactor Coolant	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-99	3.1-1, 103	B
(N-6A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N-6A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1-1, 084	A
(N-6A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-50	3.1-1, 084	A
(N-6A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1-1, 124	I, 2
(N-6A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.A1.R-448	3.1-1, 133	A
(N-6A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-6A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1-1, 084	A
(N-6A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-50	3.1-1, 084	A
(N-6A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Air-Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1-1, 124	I, 2
(N-6A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Reactor Coolant (Internal)	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.A1.R-448	3.1-1, 133	A
(N-7 Head Vent) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N-7 Head Vent) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1-1, 084	A
(N-7 Head Vent) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-50	3.1-1, 084	A
(N-7 Head Vent) Reactor Vessel Nozzle	Pressure Boundary	Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1-1, 124	I, 2
(N-7 Head Vent) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.A1.R-448	3.1-1, 133	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
(N-7 Head Vent) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	Section 4.3 "Metal Fatigue"	IV.A1.R-04	3.1-1, 007	A
(N-7 Head Vent) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1-1, 084	A
(N-7 Head Vent) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-50	3.1-1, 084	A
(N-7 Head Vent) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1-1, 124	I, 2
(N-7 Head Vent) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Reactor Coolant (Internal)	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.A1.R-448	3.1-1, 133	A
(N-8A/B Jet Pump Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cumulative Fatigue Damage	Section 4.3 "Metal Fatigue"	IV.A1.R-04	3.1-1, 007	A
(N-8A/B Jet Pump Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
(N-8A/B Jet Pump Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-8A/B Jet Pump Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1-1, 114	A
(N-8A/B Jet Pump Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
(N-8A/B Jet Pump Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1-1, 124	I, 2
(N-8A/B Jet Pump Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N-8A/B Jet Pump Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC, IGSCC	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1-1, 016	C
(N-8A/B Jet Pump Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-8A/B Jet Pump Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
(N-8A/B Jet Pump Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC	Water Chemistry (B.2.1.2)	IV.A1.R-68	3.1-1, 128	A
(N-8A/B Jet Pump Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-68	3.1-1, 128	B
(N-8A/B Jet Pump Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
(N-9 CRD Return) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cumulative Fatigue Damage	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N-9 CRD Return) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
(N-9 CRD Return) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
(N-9 CRD Return) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking due to cyclic loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.A1.R-66	3.1-1, 096	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-9 CRD Return) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1-1, 114	A
(N-9 CRD Return) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
(N-9 CRD Return) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1-1, 124	I, 2
(N-9 CRD Return) Reactor Vessel Nozzle, Safe Ends, and Welds (including cap)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N-9 CRD Return) Reactor Vessel Nozzle, Safe Ends, and Welds (including cap)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC, IGSCC	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1-1, 016	C
(N-9 CRD Return) Reactor Vessel Nozzle, Safe Ends, and Welds (including cap)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N-9 CRD Return) Reactor Vessel Nozzle, Safe Ends, and Welds (including cap)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
(N-9 CRD Return) Reactor Vessel Nozzle, Safe Ends, and Welds (including cap)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC	Water Chemistry (B.2.1.2)	IV.A1.R-412	3.1-1, 097	A
(N-9 CRD Return) Reactor Vessel Nozzle, Safe Ends, and Welds (including cap)	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC	BWR Stress Corrosion Cracking (B.2.1.5)	IV.A1.R-412	3.1-1, 097	B
(N-9 CRD Return) Reactor Vessel Nozzle, Safe Ends, and Welds (including cap)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
(N10 Core Plate D/P and SLC) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cumulative Fatigue Damage	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N10 Core Plate D/P and SLC) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
(N10 Core Plate D/P and SLC) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
(N10 Core Plate D/P and SLC) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC, cyclic loading	Water Chemistry (B.2.1.2) (SCC, IGSCC mechanisms only)	IV.A1.RP-369	3.1-1, 098	A
(N10 Core Plate D/P and SLC) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC, cyclic loading	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1-1, 098	B

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N10 Core Plate D/P and SLC) Reactor Vessel Nozzle	Pressure Boundary	Steel with Stainless Steel Cladding	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1-1, 124	I, 2
(N10 Core Plate D/P and SLC) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N10 Core Plate D/P and SLC) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC, IGSCC	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1-1, 016	C
(N10 Core Plate D/P and SLC) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
(N10 Core Plate D/P and SLC) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
(N10 Core Plate D/P and SLC) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1-1, 114	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N10 Core Plate D/P and SLC) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
(N10 Core Plate D/P and SLC) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
(N11A/B, N12A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cumulative Fatigue Damage	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N11A/B, N12A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
(N11A/B, N12A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
(N11A/B, N12A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC, cyclic loading	Water Chemistry (B.2.1.2) (SCC, IGSCC mechanisms only)	IV.A1.RP-369	3.1-1, 098	A
(N11A/B, N12A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC, cyclic loading	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1-1, 098	B
(N11A/B, N12A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N11A/B, N12A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	Section 4.3 "Metal Fatigue"	IV.A1.R-04	3.1-1, 007	A
(N11A/B, N12A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC, IGSCC	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1-1, 016	C
(N11A/B, N12A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC, cyclic loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.A1.RP-371	3.1-1, 030	C
(N11A/B, N12A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Cracking due to SCC, IGSCC, cyclic loading	Water Chemistry (B.2.1.2) (SCC, IGSCC mechanisms only)	IV.A1.RP-371	3.1-1, 030	C
(N11A/B, N12A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
(N11A/B, N12A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
(N11A/B, N12A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
(N13 Flange Leak- Off) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N13 Flange Leak- Off) Reactor Vessel Nozzle	Direct Flow	Nickel Alloy	Reactor Coolant	Cracking due to SCC, IGSCC, cyclic loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.A1.RP-371	3.1-1, 030	C
(N13 Flange Leak- Off) Reactor Vessel Nozzle	Direct Flow	Nickel Alloy	Reactor Coolant	Cracking due to SCC, IGSCC, cyclic loading	Water Chemistry (B.2.1.2) (SCC, IGSCC mechanisms only)	IV.A1.RP-371	3.1-1, 030	C
(N13 Flange Leak- Off) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1-1, 084	C
(N13 Flange Leak- Off) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-50	3.1-1, 084	C
(N13 Flange Leak- Off) Reactor Vessel Nozzle	Direct Flow	Nickel Alloy	Reactor Coolant	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
(N13 Flange Leak- Off) Reactor Vessel Nozzle	Direct Flow	Nickel Alloy	Reactor Coolant	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
(N13 Flange Leak- Off) Reactor Vessel Nozzle	Pressure Boundary	Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1-1, 124	I, 2
(N13 Flange Leak- Off) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.A1.R-448	3.1-1, 133	A
(N14 Flange Leak- Off) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N14 Flange Leak- Off) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1-1, 084	C

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N14 Flange Leak- Off) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-50	3.1-1, 084	C
(N14 Flange Leak- Off) Reactor Vessel Nozzle	Pressure Boundary	Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1-1, 124	I, 2
(N14 Flange Leak- Off) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.A1.R-448	3.1-1, 133	A
(N15 Bottom Drain) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N15 Bottom Drain) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1-1, 084	C
(N15 Bottom Drain) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-50	3.1-1, 084	C
(N15 Bottom Drain) Reactor Vessel Nozzle	Pressure Boundary	Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1-1, 124	I, 2
(N15 Bottom Drain) Reactor Vessel Nozzle	Pressure Boundary	Steel	Reactor Coolant (Internal)	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.A1.R-448	3.1-1, 133	A
(N15 Bottom Drain) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Reactor Coolant (Internal)	Cumulative Fatigue Damage	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N15 Bottom Drain) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1-1, 084	C

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N15 Bottom Drain) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Reactor Coolant (Internal)	Loss of material due to general, pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-50	3.1-1, 084	C
(N15 Bottom Drain) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Air - Indoor Uncontrolled (External)	None	None	IV.C1.R-431	3.1-1, 124	I, 2
(N15 Bottom Drain) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Steel	Reactor Coolant (Internal)	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.A1.R-448	3.1-1, 133	A
(N16A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Reactor Coolant and Neutron Flux	Cumulative Fatigue Damage	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
(N16A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
(N16A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
(N16A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, cyclic loading	Water Chemistry (B.2.1.2) (SCC, IGSCC mechanisms only)	IV.A1.RP-369	3.1-1, 098	A
(N16A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, cyclic loading	BWR Penetrations (B.2.1.6)	IV.A1.RP-369	3.1-1, 098	B
(N16A/B Instrumentation) Reactor Vessel Nozzle	Pressure Boundary	Nickel Alloy	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
(N16A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant and Neutron Flux	Cumulative Fatigue Damage	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A

Table 3.1.2-1, Reactor Vessel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
(N16A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC, IGSCC	One-Time Inspection (B.2.1.20)	IV.A1.R-61a	3.1-1, 016	C
(N16A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, cyclic loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.A1.RP-371	3.1-1, 030	C
(N16A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, cyclic loading	Water Chemistry (B.2.1.2) (SCC, IGSCC mechanisms only)	IV.A1.RP-371	3.1-1, 030	C
(N16A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
(N16A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
(N16A/B Instrumentation) Reactor Vessel Nozzle, Safe Ends, and Welds	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A

Table 3.1.2-1 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. The BWR Vessel Internals program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.
2. During power operation the insulated reactor vessel, nozzles, and safe end components have an external temperature greater than 212 degrees F and are at a higher temperature than the air-indoor (uncontrolled) environment. During plant shutdown the reactor vessel components and containment atmosphere temperatures are normally above the dewpoint temperature. Therefore, wetting due to condensation and moisture accumulation will not occur during power operation or plant shutdown and loss of material due to general, pitting, or crevice corrosion does not apply.
3. Component includes shell and nozzle components (including associated welds in the beltline region of the vessel).

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Core Shroud and Core Plate: Access hole cover (Mechanical - Units 1 and 2)	Direct Flow	Nickel Alloy	Reactor Coolant and Neutron Flux	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.B1.R-53	3.1-1, 003	A
Core Shroud and Core Plate: Access hole cover (Mechanical - Units 1 and 2)	Direct Flow	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-95	3.1-1, 041	A
Core Shroud and Core Plate: Access hole cover (Mechanical - Units 1 and 2)	Direct Flow	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-95	3.1-1, 041	B
Core Shroud and Core Plate: Access hole cover (Mechanical - Units 1 and 2)	Mechanical Closure	Nickel alloy	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-95	3.1-1, 041	A
Core Shroud and Core Plate: Access hole cover (Mechanical - Units 1 and 2)	Mechanical Closure	Nickel alloy	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-95	3.1-1, 041	B
Core Shroud and Core Plate: Access hole cover (Mechanical - Units 1 and 2)	Direct Flow	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Core Shroud and Core Plate: Access hole cover (Mechanical - Units 1 and 2)	Direct Flow	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Core Shroud and Core Plate: Access hole cover (Mechanical - Units 1 and 2)	Mechanical Closure	Nickel alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Core Shroud and Core Plate: Access hole cover (Mechanical - Units 1 and 2)	Mechanical Closure	Nickel alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Core Shroud and Core Plate: Access hole cover (Welded - Unit 3)	Direct Flow	Nickel Alloy	Reactor Coolant and Neutron Flux	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.B1.R-53	3.1-1, 003	A
Core Shroud and Core Plate: Access hole cover (Welded - Unit 3)	Direct Flow	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-94	3.1-1, 029	A
Core Shroud and Core Plate: Access hole cover (Welded - Unit 3)	Direct Flow	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-94	3.1-1, 029	B
Core Shroud and Core Plate: Access hole cover (Welded - Unit 3)	Direct Flow	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Core Shroud and Core Plate: Access hole cover (Welded - Unit 3)	Direct Flow	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Core Shroud and Core Plate: Core Shroud (upper, central, lower)	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.B1.R-53	3.1-1, 003	A

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Core Shroud and Core Plate: Core Shroud (upper, central, lower)	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Core Shroud and Core Plate: Core Shroud (upper, central, lower)	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Core Shroud and Core Plate: Core Shroud (upper, central, lower)	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of fracture toughness due to neutron irradiation embrittlement	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-200	3.1-1, 099	B
Core Shroud and Core Plate: Core Shroud (upper, central, lower)	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-92	3.1-1, 103	A
Core Shroud and Core Plate: Core Shroud (upper, central, lower)	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-92	3.1-1, 103	A

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Core Shroud and Core Plate: Core Shroud support structure (shroud support cylinder, shroud support plate, shroud support legs)	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant and Neutron Flux	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.B1.R-53	3.1-1, 003	A
Core Shroud and Core Plate: Core Shroud support structure (shroud support cylinder, shroud support plate, shroud support legs)	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Core Shroud and Core Plate: Core Shroud support structure (shroud support cylinder, shroud support plate, shroud support legs)	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Core Shroud and Core Plate: Core plate, Core plate bolts	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Core Shroud and Core Plate: Core plate, Core plate bolts	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Core Shroud and Core Plate: Core plate, Core plate bolts	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of fracture toughness due to neutron irradiation embrittlement	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-200	3.1-1, 099	B
Core Shroud and Core Plate: Core plate, Core plate bolts	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-93	3.1-1, 103	A
Core Shroud and Core Plate: Core plate, Core plate bolts	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-93	3.1-1, 103	B
Core Shroud and Core Plate: Core Shroud support structure (shroud support cylinder, shroud support plate, shroud support legs)	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-96	3.1-1, 103	A
Core Shroud and Core Plate: Core Shroud support structure (shroud support cylinder, shroud support plate, shroud support legs)	Structural Support to maintain core configuration and flow distribution	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-96	3.1-1, 103	B

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Core Shroud and Core Plate: Core plate, Core plate bolts	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.B1.R-53	3.1-1, 003	A
Core Shroud and Core Plate: Core plate, Core plate bolts	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Core Shroud and Core Plate: Core plate, Core plate bolts	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Core Shroud and Core Plate: Core plate, Core plate bolts	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-93	3.1-1, 103	A
Core Shroud and Core Plate: Core plate, Core plate bolts	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-93	3.1-1, 103	B

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Core Shroud and Core Plate: Core plate, Core plate bolts	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Preload due to thermal or irradiation-enhanced stress relaxation	BWR Vessel Internals (B.2.1.7)	IV.B1.R-420	3.1-1, 120	B
Core Shroud and Core Plate: Core plate, Core plate bolts	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of Preload due to thermal or irradiation-enhanced stress relaxation	Section 4.2 “Reactor Vessel and Internals Neutron Embrittlement”	IV.B1.R-420	3.1-1, 120	A
Core Spray Lines and Spargers: Core spray lines (headers), Spray rings, Spray nozzles, Thermal sleeves	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.B1.R-53	3.1-1, 003	A
Core Spray Lines and Spargers: Core spray lines (headers), Spray rings, Spray nozzles, Thermal sleeves	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Core Spray Lines and Spargers: Core spray lines (headers), Spray rings, Spray nozzles, Thermal sleeves	Spray	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Core Spray Lines and Spargers: Core spray lines (headers), Spray rings, Spray nozzles, Thermal sleeves	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Core Spray Lines and Spargers: Core spray lines (headers), Spray rings, Spray nozzles, Thermal sleeves	Spray	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Core Spray Lines and Spargers: Core spray lines (headers), Spray rings, Spray nozzles, Thermal sleeves	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-99	3.1-1, 103	A
Core Spray Lines and Spargers: Core spray lines (headers), Spray rings, Spray nozzles, Thermal sleeves	Spray	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-99	3.1-1, 103	A
Core Spray Lines and Spargers: Core spray lines (headers), Spray rings, Spray nozzles, Thermal sleeves	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-99	3.1-1, 103	B
Core Spray Lines and Spargers: Core spray lines (headers), Spray rings, Spray nozzles, Thermal sleeves	Spray	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-99	3.1-1, 103	B
Core Spray Sparger Nozzle Elbows	Direct Flow	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.B1.R-53	3.1-1, 003	A
Core Spray Sparger Nozzle Elbows	Direct Flow	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Core Spray Sparger Nozzle Elbows	Direct Flow	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Core Spray Sparger Nozzle Elbows	Direct Flow	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of fracture toughness due to thermal aging, neutron irradiation embrittlement	BWR Vessel Internals (B.2.1.7)	IV.B1.R-417	3.1-1, 099	B
Core Spray Sparger Nozzle Elbows	Direct Flow	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-99	3.1-1, 103	A
Core Spray Sparger Nozzle Elbows	Direct Flow	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-99	3.1-1, 103	B
CRD Housing	Pressure Boundary	Stainless Steel	Reactor Coolant	Cracking due to SCC, IGSCC	Water Chemistry (B.2.1.2)	IV.B1.R-104	3.1-1, 102	A
CRD Housing	Structural Support	Stainless Steel	Reactor Coolant	Cracking due to SCC, IGSCC	Water Chemistry (B.2.1.2)	IV.B1.R-104	3.1-1, 102	A
CRD Housing	Pressure Boundary	Stainless Steel	Reactor Coolant	Cracking due to SCC, IGSCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-104	3.1-1, 102	B
CRD Housing	Structural Support	Stainless Steel	Reactor Coolant	Cracking due to SCC, IGSCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-104	3.1-1, 102	B
CRD Housing	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	IV.B1.R-104	None	G, 3
CRD Housing	Structural Support	Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	IV.B1.R-104	None	G, 3

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
In-core Instrumentation: Intermediate Range Monitor Dry Tubes, Local Power Range Monitor Dry Tubes, Source Range Monitor Dry Tubes, and In-core Neutron Flux Monitor (Traversing Incore Probe) Guide Tubes	Pressure Boundary	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
In-core Instrumentation: Intermediate Range Monitor Dry Tubes, Local Power Range Monitor Dry Tubes, Source Range Monitor Dry Tubes, and In-core Neutron Flux Monitor (Traversing Incore Probe) Guide Tubes	Pressure Boundary	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
In-core Instrumentation: Intermediate Range Monitor Dry Tubes, Local Power Range Monitor Dry Tubes, Source Range Monitor Dry Tubes, and In-core Neutron Flux Monitor (Traversing Incore Probe) Guide Tubes	Pressure Boundary	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of fracture toughness due to neutron irradiation embrittlement	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-200	3.1-1, 099	B

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
In-core Instrumentation: Intermediate Range Monitor Dry Tubes, Local Power Range Monitor Dry Tubes, Source Range Monitor Dry Tubes, and In-core Neutron Flux Monitor (Traversing Incore Probe) Guide Tubes	Pressure Boundary	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-105	3.1-1, 103	A
In-core Instrumentation: Intermediate Range Monitor Dry Tubes, Local Power Range Monitor Dry Tubes, Source Range Monitor Dry Tubes, and In-core Neutron Flux Monitor (Traversing Incore Probe) Guide Tubes	Pressure Boundary	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-105	3.1-1, 103	B
IIn-core Instrumentation: Intermediate Range Monitor Dry Tubes, Local Power Range Monitor Dry Tubes, Source Range Monitor Dry Tubes, and In-core Neutron Flux Monitor (Traversing Incore Probe) Guide Tubes	Pressure Boundary	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-422	3.1-1, 103	A

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
In-core Instrumentation: Intermediate Range Monitor Dry Tubes, Local Power Range Monitor Dry Tubes, Source Range Monitor Dry Tubes, and In-core Neutron Flux Monitor (Traversing Incore Probe) Guide Tubes	Pressure Boundary	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-422	3.1-1, 103	B
Jet Pump Assemblies: Castings (Inlet elbow, Mixing assembly, Diffuser casting, Restrainer Bracket)	Direct Flow	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.B1.R-53	3.1-1, 003	A
Jet Pump Assemblies: Castings (Inlet elbow, Mixing assembly, Diffuser casting, Restrainer Bracket)	Direct Flow	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Jet Pump Assemblies: Castings (Inlet elbow, Mixing assembly, Diffuser casting, Restrainer Bracket)	Direct Flow	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Jet Pump Assemblies: Castings (Inlet elbow, Mixing assembly, Diffuser casting, Restrainer Bracket)	Direct Flow	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of fracture toughness due to thermal aging, neutron irradiation embrittlement	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-219	3.1-1, 099	B
Jet Pump Assemblies: Castings (Inlet elbow, Mixing assembly, Diffuser casting, Restrainer Bracket)	Direct Flow	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1-1, 103	A

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Jet Pump Assemblies: Castings (Inlet elbow, Mixing assembly, Diffuser casting, Restrainer Bracket)	Direct Flow	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1-1, 103	B
Jet Pump Assemblies: Hold- down beam bolts	Mechanical Closure	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Jet Pump Assemblies: Hold- down beam bolts	Mechanical Closure	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Jet Pump Assemblies: Hold- down beam bolts	Mechanical Closure	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1-1, 103	A
Jet Pump Assemblies: Hold- down beam bolts	Mechanical Closure	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1-1, 103	B
Jet Pump Assemblies: Hold- down beam bolts	Mechanical Closure	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of preload due to thermal or irradiation-enhanced stress relaxation	BWR Vessel Internals (B.2.1.7)	IV.B1.R-421	3.1-1, 121	B
Jet Pump Assemblies: Jet pump sensing line	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.B1.R-53	3.1-1, 003	A
Jet Pump Assemblies: Jet pump sensing line	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Jet Pump Assemblies: Jet pump sensing line	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Jet Pump Assemblies: Jet pump sensing line	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1-1, 103	A
Jet Pump Assemblies: Jet pump sensing line	Direct Flow	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1-1, 103	B
Jet Pump Assemblies: Thermal sleeve inlet header, Riser brace arm, Hold- down beams, and Wedges	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.B1.R-53	3.1-1, 003	A
Jet Pump Assemblies: Thermal sleeve inlet header, Riser brace arm, Hold- down beams, and Wedges	Structural Support	Nickel alloy	Reactor Coolant and Neutron Flux	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.B1.R-53	3.1-1, 003	A
Jet Pump Assemblies: Thermal sleeve inlet header, Riser brace arm, Hold- down beams, and Wedges	Structural Support	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Jet Pump Assemblies: Thermal sleeve inlet header, Riser brace arm, Hold- down beams, and Wedges	Structural Support	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Jet Pump Assemblies: Thermal sleeve inlet header, Riser brace arm, Hold- down beams, and Wedges	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Jet Pump Assemblies: Thermal sleeve inlet header, Riser brace arm, Hold- down beams, and Wedges	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Jet Pump Assemblies: Thermal sleeve inlet header, Riser brace arm, Hold- down beams, and Wedges	Structural Support	Nickel alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Jet Pump Assemblies: Thermal sleeve inlet header, Riser brace arm, Hold- down beams, and Wedges	Structural Support	Nickel alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Jet Pump Assemblies: Thermal sleeve inlet header, Riser brace arm, Hold- down beams, and Wedges	Structural Support	Nickel alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	H, 2
Jet Pump Assemblies: Thermal sleeve inlet header, Riser brace arm, Hold- down beams, and Wedges	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to wear	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-377	3.1-1, 100	B
Jet Pump Assemblies: Thermal sleeve inlet header, Riser brace arm, Hold- down beams, and Wedges	Structural Support	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1-1, 103	A

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Jet Pump Assemblies: Thermal sleeve inlet header, Riser brace arm, Hold- down beams, and Wedges	Structural Support	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1-1, 103	B
Jet Pump Assemblies: Thermal sleeve inlet header, Riser brace arm, Hold- down beams, and Wedges	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1-1, 103	A
Jet Pump Assemblies: Thermal sleeve inlet header, Riser brace arm, Hold- down beams, and Wedges	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1-1, 103	B
Jet Pump Assemblies: Thermal sleeve inlet header, Riser brace arm, Hold- down beams, and Wedges	Structural Support	Nickel alloy	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1-1, 103	A
Jet Pump Assemblies: Thermal sleeve inlet header, Riser brace arm, Hold- down beams, and Wedges	Structural Support	Nickel alloy	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1-1, 103	B
Reactor Vessel Internal Components	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Reactor Vessel Internal Components	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.A1.R-04	3.1-1, 007	A
Reactor Vessel Internal Components	Structural Support to maintain core configuration and flow distribution	Steel	Reactor Coolant	Loss of material due to general, pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-50	3.1-1, 084	C
Reactor Vessel Internal Components	Structural Support to maintain core configuration and flow distribution	Steel	Reactor Coolant	Loss of material due to general, pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-50	3.1-1, 084	C
Reactor Vessel Internal Components	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
Reactor Vessel Internal Components	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Reactor Vessel Internal Components	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.A1.RP-157	3.1-1, 085	A
Reactor Vessel Internal Components	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.A1.RP-157	3.1-1, 085	A
Reactor Vessel Internal Components	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant	Cracking due to SCC, IGSCC, cyclic loading	Water Chemistry (B.2.1.2) (SCC, IGSCC mechanisms only)	IV.A1.R-64	3.1-1, 094	A
Reactor Vessel Internal Components	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant	Cracking due to SCC, IGSCC, cyclic loading	BWR Vessel ID Attachment Welds (B.2.1.4)	IV.A1.R-64	3.1-1, 094	B
Reactor Vessel Internal Components	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, cyclic loading	Water Chemistry (B.2.1.2) (SCC, IGSCC mechanisms only)	IV.A1.R-64	3.1-1, 094	A

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel Internal Components	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, cyclic loading	BWR Vessel ID Attachment Welds (B.2.1.4)	IV.A1.R-64	3.1-1, 094	B
Reactor Vessel Internal Components	Structural Support to maintain core configuration and flow distribution	Steel	Reactor Coolant	Long-Term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.A1.R-448	3.1-1, 133	A
Reactor Vessel Internals Components (Core Spray Repair Hardware)	Pressure Boundary	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Reactor Vessel Internals Components (Core Spray Repair Hardware)	Pressure Boundary	Nickel Alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Reactor Vessel Internals Components (Core Spray Repair Hardware)	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Reactor Vessel Internals Components (Core Spray Repair Hardware)	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Reactor Vessel Internals Components (Core Spray Repair Hardware)	Structural Support	Nickel alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel Internals Components (Core Spray Repair Hardware)	Structural Support	Nickel alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Reactor Vessel Internals Components (Core Spray Repair Hardware)	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-99	3.1-1, 103	C
Reactor Vessel Internals Components (Core Spray Repair Hardware)	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-99	3.1-1, 103	D
Reactor Vessel Internals Components (Core Spray Repair Hardware)	Pressure Boundary	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking due to IGSCC	Water Chemistry (B.2.1.2)	IV.B1.RP-381	3.1-1, 104	A
Reactor Vessel Internals Components (Core Spray Repair Hardware)	Pressure Boundary	Nickel Alloy	Reactor Coolant and Neutron Flux	Cracking due to IGSCC	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-381	3.1-1, 104	B
Reactor Vessel Internals Components (Core Spray Repair Hardware)	Structural Support	Nickel alloy	Reactor Coolant and Neutron Flux	Cracking due to IGSCC	Water Chemistry (B.2.1.2)	IV.B1.RP-381	3.1-1, 104	A
Reactor Vessel Internals Components (Core Spray Repair Hardware)	Structural Support	Nickel alloy	Reactor Coolant and Neutron Flux	Cracking due to IGSCC	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-381	3.1-1, 104	B

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.B1.R-53	3.1-1, 003	A
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Throttle	Stainless Steel	Reactor Coolant and Neutron Flux	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.B1.R-53	3.1-1, 003	A
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Structural Support to maintain core configuration and flow distribution	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Structural Support to maintain core configuration and flow distribution	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Throttle	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Throttle	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Throttle	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Throttle	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Structural Support to maintain core configuration and flow distribution	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of fracture toughness due to thermal aging, neutron irradiation embrittlement	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-220	3.1-1, 099	B
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Throttle	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Loss of fracture toughness due to thermal aging, neutron irradiation embrittlement	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-220	3.1-1, 099	B

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Structural Support to maintain core configuration and flow distribution	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC	Water Chemistry (B.2.1.2)	IV.B1.R-104	3.1-1, 102	A
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Structural Support to maintain core configuration and flow distribution	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-104	3.1-1, 102	B
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Throttle	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC	Water Chemistry (B.2.1.2)	IV.B1.R-104	3.1-1, 102	A
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Throttle	Cast Austenitic Stainless Steel (CASS)	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-104	3.1-1, 102	B
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC	Water Chemistry (B.2.1.2)	IV.B1.R-104	3.1-1, 102	A
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Throttle	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC	Water Chemistry (B.2.1.2)	IV.B1.R-104	3.1-1, 102	A

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-104	3.1-1, 102	B
Reactor Vessel Internals Components: Fuel Supports and Control Rod Drive Assemblies	Throttle	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-104	3.1-1, 102	B
Reactor Vessel Internals Components (Jet Pump Auxiliary Spring Wedges)	Structural Support	Nickel alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Reactor Vessel Internals Components (Jet Pump Auxiliary Spring Wedges)	Structural Support	Nickel alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Reactor Vessel Internals Components (Jet Pump Auxiliary Spring Wedges)	Structural Support	Nickel alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	H, 2
Reactor Vessel Internals Components (Jet Pump Auxiliary Spring Wedges)	Structural Support	Nickel alloy	Reactor Coolant and Neutron Flux	Cracking due to IGSCC	Water Chemistry (B.2.1.2)	IV.B1.RP-381	3.1-1, 104	A
Reactor Vessel Internals Components (Jet Pump Auxiliary Spring Wedges)	Structural Support	Nickel alloy	Reactor Coolant and Neutron Flux	Cracking due to IGSCC	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-381	3.1-1, 104	B

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel Internals Components (Jet Pump Riser Clamps)	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Reactor Vessel Internals Components (Jet Pump Riser Clamps)	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Reactor Vessel Internals Components (Jet Pump Riser Clamps)	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1-1, 103	C
Reactor Vessel Internals Components (Jet Pump Riser Clamps)	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1-1, 103	D
Reactor Vessel Internals Components (Jet Pump Slip Joint Clamps)	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Reactor Vessel Internals Components (Jet Pump Slip Joint Clamps)	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Reactor Vessel Internals Components (Jet Pump Slip Joint Clamps)	Structural Support	Nickel alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Reactor Vessel Internals Components (Jet Pump Slip Joint Clamps)	Structural Support	Nickel alloy	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor Vessel Internals Components (Jet Pump Slip Joint Clamps)	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-100	3.1-1, 103	C
Reactor Vessel Internals Components (Jet Pump Slip Joint Clamps)	Structural Support	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-100	3.1-1, 103	D
Reactor Vessel Internals Components (Jet Pump Slip Joint Clamps)	Structural Support	Nickel alloy	Reactor Coolant and Neutron Flux	Cracking due to IGSCC	Water Chemistry (B.2.1.2)	IV.B1.RP-381	3.1-1, 104	A
Reactor Vessel Internals Components (Jet Pump Slip Joint Clamps)	Structural Support	Nickel alloy	Reactor Coolant and Neutron Flux	Cracking due to IGSCC	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-381	3.1-1, 104	B
Reactor Vessel Internals Components: Steam Dryers	Structural Support	Stainless Steel	Reactor Coolant	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Reactor Vessel Internals Components: Steam Dryers	Structural Support	Stainless Steel	Reactor Coolant	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Reactor Vessel Internals Components: Steam Dryers	Structural Support	Stainless Steel	Reactor Coolant	Cracking due to flow-induced vibration; SCC, IGSCC; loss of material due to wear	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-155	3.1-1, 101	B
Reactor Vessel Internals Components: Top Guide	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.B1.R-53	3.1-1, 003	A

Table 3.1.2-2, Reactor Vessel Internals - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Reactor Vessel Internals Components: Top Guide	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.B1.RP-26	3.1-1, 043	A
Reactor Vessel Internals Components: Top Guide	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of material due to pitting, crevice corrosion	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-26	3.1-1, 043	E, 1
Reactor Vessel Internals Components: Top Guide	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Loss of fracture toughness due to neutron irradiation embrittlement	BWR Vessel Internals (B.2.1.7)	IV.B1.RP-200	3.1-1, 099	B
Reactor Vessel Internals Components: Top Guide	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Water Chemistry (B.2.1.2)	IV.B1.R-98	3.1-1, 103	A
Reactor Vessel Internals Components: Top Guide	Structural Support to maintain core configuration and flow distribution	Stainless Steel	Reactor Coolant and Neutron Flux	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals (B.2.1.7)	IV.B1.R-98	3.1-1, 103	B

Table 3.1.2-2 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. The BWR Vessel Internals program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.
2. The BWR Vessel Internals program is used to manage loss of material due to wear of nickel alloy jet pump wedges.
3. Aging effects identified for this material/environment combination are consistent with industry guidance (BWRVIP-47-A, BWRVIP-06 Revision 1-A, BWRVIP-315).

Table 3.1.2-3, Reactor Vessel Vents and Drains System – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Bolting (Closure)	Mechanical Closure	Steel	Air - Indoor Uncontrolled (External)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.RP-44	3.1-1, 011	A
Bolting (Closure)	Mechanical Closure	High Strength Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC	Bolting Integrity (B.2.1.10)	IV.C1.R-11	3.1-1, 062	A
Bolting (Closure)	Mechanical Closure	Steel	Air - Indoor Uncontrolled (External)	Loss of material due to general (steel only), pitting, crevice corrosion, wear	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1-1, 063	A
Bolting (Closure)	Mechanical Closure	Steel	Air - Indoor Uncontrolled (External)	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1-1, 067	A
Piping, Piping Components	Pressure Boundary	Steel	Air - Indoor Uncontrolled (External)	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Piping, Piping Components	Pressure Boundary	Steel	Treated Water (external)	Long-Term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1-1, 133	A
Piping, Piping Components	Pressure Boundary	Stainless Steel	Treated Water (external)	Long-Term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1-1, 133	A
Piping, Piping Components	Pressure Boundary	Steel	Air (internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A

Table 3.1.2-3, Reactor Vessel Vents and Drains System – Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Piping, Piping Components	Pressure Boundary	Stainless Steel	Air (internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Piping, Piping Components (Class 1)	Pressure Boundary	Steel	Treated Water (internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1-1, 079	G, 1
Piping, Piping Components (Class 1)	Pressure Boundary	Steel	Treated Water (internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	G, 1
Piping, Piping Components (Class 1)	Pressure Boundary	Stainless Steel	Treated Water (internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1-1, 079	G, 1
Piping, Piping Components (Class 1)	Pressure Boundary	Stainless Steel	Treated Water (internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	G, 1
Piping, Piping Components (Class 1)	Pressure Boundary	Stainless Steel	Treated Water (internal)	Cracking due to SCC, IGSCC	Water Chemistry (B.2.1.2)	IV.C1.R-20	3.1-1, 097	G, 1
Piping, Piping Components (Class 1)	Pressure Boundary	Stainless Steel	Treated Water (internal)	Cracking due to SCC, IGSCC	BWR Stress Corrosion Cracking (B.2.1.5)	IV.C1.R-20	3.1-1, 097	G, 1
Piping, Piping Components (Class 1)	Pressure Boundary	Steel	Treated Water (internal)	Wall thinning due to erosion.	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-406	3.1-1, 110	G, 1
Piping, Piping Components (Class 1)	Pressure Boundary	Steel	Air - Indoor Uncontrolled (External)	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Piping, Piping Components (Class 1)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Piping, Piping Components (Class 1)	Pressure Boundary	Steel	Treated Water (internal)	Long-Term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1-1, 133	A
Piping, Piping Components (Class 1)	Pressure Boundary	Stainless Steel	Treated Water (internal)	Long-Term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1-1, 133	A

Table 3.1.2-3, Reactor Vessel Vents and Drains System – Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, Piping Components (Class 1)	Pressure Boundary	Steel	Air (internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Piping, Piping Components (Class 1)	Pressure Boundary	Stainless Steel	Air (internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Piping, Piping Components (Valve Body)	Pressure Boundary	Steel	Air - Indoor Uncontrolled (External)	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Piping, Piping Components (Valve Body)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Piping, Piping Components (Valve Body)	Pressure Boundary	Steel	Air (internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	H, 1
Piping, Piping Components (Valve Body)	Pressure Boundary	Stainless Steel	Air (internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	H, 1
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Steel	Treated Water (internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 "Metal Fatigue"	IV.C1.R-220	3.1-1, 006	G, 1
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Treated Water (internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 "Metal Fatigue"	IV.C1.R-220	3.1-1, 006	G, 1
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel - CASS	Treated Water (internal)	Loss of fracture toughness due to thermal aging embrittlement	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.R-08	3.1-1, 038	G, 1
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Steel	Treated Water (internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1-1, 079	G, 1

Table 3.1.2-3, Reactor Vessel Vents and Drains System – Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Steel	Treated Water (internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	G, 1
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Treated Water (internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1-1, 079	G, 1
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Treated Water (internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	G, 1
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Treated Water (internal)	Cracking due to SCC, IGSCC	Water Chemistry (B.2.1.2)	IV.C1.R-20	3.1-1, 097	G, 1
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Treated Water (internal)	Cracking due to SCC, IGSCC	BWR Stress Corrosion Cracking (B.2.1.5)	IV.C1.R-20	3.1-1, 097	G, 1
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Steel	Treated Water (internal)	Wall thinning due to erosion.	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-406	3.1-1, 110	G, 1
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Steel	Air - Indoor Uncontrolled (External)	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Steel	Treated Water (internal)	Long-Term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1-1, 133	A
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Treated Water (internal)	Long-Term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1-1, 133	A

Table 3.1.2-3, Reactor Vessel Vents and Drains System – Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel - CASS	Treated Water (internal)	Long-Term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1-1, 133	A
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Steel	Air (internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	H, 1
Piping, Piping Components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Air (internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A

Table 3.1.2-3 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. The aging effects identified for this material/environment combination are consistent with industry experience.

Table 3.1.2-4, Reactor Recirculation System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Bolting (Class 1)	Mechanical Closure	Steel	Air - Indoor Uncontrolled (External)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.RP-44	3.1-1, 011	A
Bolting (Class 1)	Mechanical Closure	High-strength steel	Air - Indoor Uncontrolled (External)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.RP-44	3.1-1, 011	A
Bolting (Class 1)	Mechanical Closure	High-strength steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC	Bolting Integrity (B.2.1.10)	IV.C1.R-11	3.1-1, 062	A
Bolting (Class 1)	Mechanical Closure	Steel	Air - Indoor Uncontrolled (External)	Loss of material due to general (steel only), pitting, crevice corrosion, wear	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1-1, 063	A
Bolting (Class 1)	Mechanical Closure	High-strength steel	Air - Indoor Uncontrolled (External)	Loss of material due to general (steel only), pitting, crevice corrosion, wear	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1-1, 063	A
Bolting (Class 1)	Mechanical Closure	Steel	Air - Indoor Uncontrolled (External)	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1-1, 067	A
Bolting (Class 1)	Mechanical Closure	High-strength steel	Air - Indoor Uncontrolled (External)	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1-1, 067	A
Bolting (Closure)	Mechanical Closure	Steel	Air - Indoor Uncontrolled (External)	Loss of material due to general (steel only), pitting, crevice corrosion, wear	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1-1, 063	A
Bolting (Closure)	Mechanical Closure	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to general (steel only), pitting, crevice corrosion, wear	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1-1, 063	A

Table 3.1.2-4, Reactor Recirculation System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Bolting (Closure)	Mechanical Closure	Steel	Air - Indoor Uncontrolled (External)	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1-1, 067	A
Bolting (Closure)	Mechanical Closure	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1-1, 067	A
Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Flow Device	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Flow Device	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A
Flow Device	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A
Flow Device	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2-1, 022	A
Flow Device	Throttle	Stainless Steel	Treated Water (Internal)	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2-1, 022	A
Flow Device	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of material due to pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	V.D2.EP-73	3.2-1, 022	A
Flow Device	Throttle	Stainless Steel	Treated Water (Internal)	Loss of material due to pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	V.D2.EP-73	3.2-1, 022	A

Table 3.1.2-4, Reactor Recirculation System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flow Device (Class 1)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Flow Device (Class 1)	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Flow Device (Class 1)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A
Flow Device (Class 1)	Throttle	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A
Flow Device (Class 1)	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1-1, 114	A
Flow Device (Class 1)	Throttle	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1-1, 114	A

Table 3.1.2-4, Reactor Recirculation System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flow Device (Class 1)	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	Water Chemistry (B.2.1.2)	IV.E.R-444	3.1-1, 114	A
Flow Device (Class 1)	Throttle	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	Water Chemistry (B.2.1.2)	IV.E.R-444	3.1-1, 114	A
Flow Device (Class 1)	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A
Flow Device (Class 1)	Throttle	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A
Flow Device (Class 1)	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	A
Flow Device (Class 1)	Throttle	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	A
Flow Device (Class 1)	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1-1, 079	A

Table 3.1.2-4, Reactor Recirculation System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Flow Device (Class 1)	Throttle	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1-1, 079	A
Heat Exchanger - (Recirculation Pump Seal Cooler) Shell Side Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	C
Heat Exchanger - (Recirculation Pump Seal Cooler) Shell Side Components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	C
Heat Exchanger - (Recirculation Pump Seal Cooler) Shell Side Components	Pressure Boundary	Stainless Steel	Closed-cycle cooling water (External)	Loss of material due to pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	V.D2.EP-93	3.2-1, 031	A, 1
Heat Exchanger - (Recirculation Pump Seal Cooler) Shell Side Components	Pressure Boundary	Stainless Steel	Closed-cycle cooling water (External)	Cracking due to SCC	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-192	3.3-1, 044	A, 1
Heat Exchanger - (Recirculation Pump Seal Cooler) Tubes	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2-1, 022	A
Heat Exchanger - (Recirculation Pump Seal Cooler) Tubes	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Loss of material due to pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	V.D2.EP-73	3.2-1, 022	A
Heat Exchanger - (Recirculation Pump Seal Cooler) Tubes	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Cracking due to SCC	Water Chemistry (B.2.1.2)	VII.E3.AP-112	3.3-1, 020	A
Heat Exchanger - (Recirculation Pump Seal Cooler) Tubes	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.E3.AP-112	3.3-1, 020	A

Table 3.1.2-4, Reactor Recirculation System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat Exchanger - Variable Frequency Drives	Pressure Boundary	Stainless Steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	C
Heat Exchanger - Variable Frequency Drives	Pressure Boundary	Stainless Steel	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	C
Heat Exchanger - Variable Frequency Drives	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of material due to pitting, crevice corrosion, MIC, flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	V.D2.EP-91	3.2-1, 025	B
Heat Exchanger - Variable Frequency Drives	Pressure Boundary	Stainless Steel	Closed Cycle Cooling Warer (Internal)	Loss of material due to pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	V.D2.EP-93	3.2-1, 031	A
Piping, piping components (Hoses)	Pressure Boundary	Stainless Steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Piping, piping components (Hoses)	Pressure Boundary	Stainless Steel	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A
Piping, piping components (Hoses)	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2)	V.C.EP-63	3.2-1, 022	A
Piping, piping components (Hoses)	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Loss of material due to pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	V.C.EP-63	3.2-1, 022	A
Piping, piping components (Hoses)	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2-1, 022	A
Piping, piping components (Hoses)	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of material due to pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	V.D2.EP-73	3.2-1, 022	A

Table 3.1.2-4, Reactor Recirculation System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components (Hoses)	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Cracking due to SCC	Water Chemistry (B.2.1.2)	V.C.E-457	3.2-1, 114	A
Piping, piping components (Hoses)	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.C.E-457	3.2-1, 114	A
Piping, piping components (Hoses)	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of material due to pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	VII.E4.AP-138	3.3-1, 100	A
Piping, piping components (Hoses)	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of material due to pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25)	VII.E4.AP-138	3.3-1, 100	A
Piping, piping components	Pressure Boundary	Steel	Air - Indoor Uncontrolled (External)	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Piping, piping components	Pressure Boundary	Steel	Treated Water (Internal)	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1-1, 133	A
Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Piping, piping components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Air - Indoor Uncontrolled (External)	Cracking due to SCC	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-454	3.4-1, 106	A
Piping, piping components	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A
Piping, piping components	Pressure Boundary	Steel	Treated Water (Internal)	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2-1, 016	A

Table 3.1.2-4, Reactor Recirculation System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Treated Water (Internal)	Loss of material due to general, pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	V.D2.EP-60	3.2-1, 016	A
Piping, piping components	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2)	V.C.EP-63	3.2-1, 022	A
Piping, piping components	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Loss of material due to pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	V.C.EP-63	3.2-1, 022	A
Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2-1, 022	A
Piping, piping components	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of material due to pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	V.D2.EP-73	3.2-1, 022	A
Piping, piping components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Treated Water (Internal)	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	V.D2.EP-27	3.2-1, 034	A
Piping, piping components	Pressure Boundary	Steel	Lubricating Oil (Internal)	Loss of material due to pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	V.D2.EP-77	3.2-1, 049	A
Piping, piping components	Pressure Boundary	Steel	Lubricating Oil (Internal)	Loss of material due to pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25)	V.D2.EP-77	3.2-1, 049	A
Piping, piping components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (Internal)	Loss of material due to pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	V.D2.EP-76	3.2-1, 050	A
Piping, piping components	Pressure Boundary	Copper Alloy with Greater Than 15% Zinc	Lubricating Oil (Internal)	Loss of material due to pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25)	V.D2.EP-76	3.2-1, 050	A

Table 3.1.2-4, Reactor Recirculation System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Cracking due to SCC	Water Chemistry (B.2.1.2)	V.C.E-457	3.2-1, 114	A
Piping, piping components	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.C.E-457	3.2-1, 114	A
Piping, piping components	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of material due to pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	VII.E4.AP-138	3.3-1, 100	A
Piping, piping components	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of material due to pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25)	VII.E4.AP-138	3.3-1, 100	A
Piping elements	Pressure Boundary	Glass	Air - Indoor Uncontrolled (External)	None	None	V.F.EP-15	3.2-1, 060	A
Piping elements	Pressure Boundary	Glass	Lubricating Oil (Internal)	None	None	V.F.EP-16	3.2-1, 060	A
Piping elements	Pressure Boundary	Glass	Treated Water (Internal)	None	None	V.F.EP-29	3.2-1, 060	A
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Treated water >93°C [>200°F] (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Treated water >93°C [>200°F] (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1-1, 079	A
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Treated water >93°C [>200°F] (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	A

Table 3.1.2-4, Reactor Recirculation System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Treated water >93°C [>200°F] (Internal)	Cracking due to SCC, IGSCC	Water Chemistry (B.2.1.2)	IV.C1.R-20	3.1-1, 097	A
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Treated water >93°C [>200°F] (Internal)	Cracking due to SCC, IGSCC	BWR Stress Corrosion Cracking (B.2.1.5)	IV.C1.R-20	3.1-1, 097	B
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Piping, piping components: Class 1 greater than or equal to 4" NPS	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Steel	Treated Water (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A

Table 3.1.2-4, Reactor Recirculation System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Steel	Treated Water (Internal)	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), thermal, mechanical, vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1-1, 039	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Steel	Treated Water (Internal)	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), thermal, mechanical, vibratory loading	Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1-1, 039	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Steel	Treated Water (Internal)	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), thermal, mechanical, vibratory loading	ASME Code Class 1 Small-Bore Piping (B.2.1.22)	IV.C1.RP-230	3.1-1, 039	A

Table 3.1.2-4, Reactor Recirculation System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	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), thermal, mechanical, vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.RP-230	3.1-1, 039	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	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), thermal, mechanical, vibratory loading	Water Chemistry (B.2.1.2)	IV.C1.RP-230	3.1-1, 039	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	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), thermal, mechanical, vibratory loading	ASME Code Class 1 Small-Bore Piping (B.2.1.22)	IV.C1.RP-230	3.1-1, 039	A

Table 3.1.2-4, Reactor Recirculation System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Steel	Treated Water (Internal)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-23	3.1-1, 060	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1-1, 079	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Steel	Air - Indoor Uncontrolled (External)	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Steel	Treated Water (Internal)	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1-1, 133	A

Table 3.1.2-4, Reactor Recirculation System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Steel	Treated Water (Internal)	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2-1, 016	A
Piping, piping components: Class 1 piping, fittings and branch connections less than 4" NPS and greater than or equal to 1" NPS	Pressure Boundary	Steel	Treated Water (Internal)	Loss of material due to general, pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	V.D2.EP-60	3.2-1, 016	A
Pump Casing (Recirculation Pump)	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Treated water >250°C [>482°F] (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A
Pump Casing (Recirculation Pump)	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Treated water >250°C [>482°F] (Internal)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B.2.1.8)	IV.C1.R-52	3.1-1, 050	A

Table 3.1.2-4, Reactor Recirculation System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump Casing (Recirculation Pump)	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Treated water >250°C [>482°F] (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1-1, 079	A
Pump Casing (Recirculation Pump)	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Treated water >250°C [>482°F] (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	A
Pump Casing (Recirculation Pump)	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Treated water >250°C [>482°F] (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1-1, 114	A
Pump Casing (Recirculation Pump)	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Treated water >250°C [>482°F] (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
Pump Casing (Recirculation Pump)	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-431	3.1-1, 124	A
Pump Casing (Recirculation Pump)	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Air - Indoor Uncontrolled (External)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A

Table 3.1.2-4, Reactor Recirculation System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components (Strainers)	Filter	Steel	Air - Indoor Uncontrolled (External)	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Piping, piping components (Strainers)	Filter	Steel	Lubricating Oil (Internal)	Loss of material due to pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	V.D2.EP-77	3.2-1, 049	A
Piping, piping components (Strainers)	Filter	Steel	Lubricating Oil (Internal)	Loss of material due to pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25)	V.D2.EP-77	3.2-1, 049	A
Tanks (Recirculation Pump Motor Upper and Lower Bearing Oil Reservoir)	Pressure Boundary	Steel	Air - Indoor Uncontrolled (External)	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Tanks (Recirculation Pump Motor Upper and Lower Bearing Oil Reservoir)	Pressure Boundary	Steel	Lubricating Oil (Internal)	Loss of material due to general, pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	V.D2.EP-77	3.2-1, 049	C
Tanks (Recirculation Pump Motor Upper and Lower Bearing Oil Reservoir)	Pressure Boundary	Steel	Lubricating Oil (Internal)	Loss of material due to general, pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25)	V.D2.EP-77	3.2-1, 049	C
Piping, piping components (Valve Body)	Pressure Boundary	Steel	Air - Indoor Uncontrolled (External)	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Piping, piping components (Valve Body)	Pressure Boundary	Steel	Treated Water (Internal)	Long-Term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1-1, 133	A
Piping, piping components (Valve Body)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A

Table 3.1.2-4, Reactor Recirculation System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components (Valve Body)	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Air - Indoor Uncontrolled (External)	None	None	IV.E.R-453	3.1-1, 137	A
Piping, piping components (Valve Body)	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A
Piping, piping components (Valve Body)	Pressure Boundary	Steel	Treated Water (Internal)	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2-1, 016	A
Piping, piping components (Valve Body)	Pressure Boundary	Steel	Treated Water (Internal)	Loss of material due to general, pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	V.D2.EP-60	3.2-1, 016	A
Piping, piping components (Valve Body)	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2)	V.D2.EP-73	3.2-1, 022	A
Piping, piping components (Valve Body)	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of material due to pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	V.D2.EP-73	3.2-1, 022	A
Piping, piping components (Valve Body)	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Lubricating Oil (Internal)	Loss of material due to pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	V.D2.EP-76	3.2-1, 050	A
Piping, piping components (Valve Body)	Pressure Boundary	Copper Alloy with 15% Zinc or Less	Lubricating Oil (Internal)	Loss of material due to pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25)	V.D2.EP-76	3.2-1, 050	A
Piping, piping components (Valve Body)	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of material due to pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	VII.E4.AP-138	3.3-1, 100	A
Piping, piping components (Valve Body)	Pressure Boundary	Stainless Steel	Lubricating Oil (Internal)	Loss of material due to pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25)	VII.E4.AP-138	3.3-1, 100	A

Table 3.1.2-4, Reactor Recirculation System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Steel	Treated Water (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Treated water >250°C [>482°F] (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Treated water >250°C [>482°F] (Internal)	Loss of fracture toughness due to thermal aging embrittlement	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.R-08	3.1-1, 038	A
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Treated water >250°C [>482°F] (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1-1, 079	A
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Treated water >250°C [>482°F] (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	A
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1-1, 079	A
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Treated Water (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	A

Table 3.1.2-4, Reactor Recirculation System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2)	IV.C1.RP-158	3.1-1, 079	A
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	A
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Treated water >250°C [>482°F] (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1-1, 114	A
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Treated water >250°C [>482°F] (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.E.R-444	3.1-1, 114	A

Table 3.1.2-4, Reactor Recirculation System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Treated water >60°C [>140°F] (Internal)	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Steel	Air - Indoor Uncontrolled (External)	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-431	3.1-1, 124	A
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Steel	Treated Water (Internal)	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1-1, 133	A
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Cast Austenitic Stainless Steel (CASS)	Air - Indoor Uncontrolled (External)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A

Table 3.1.2-4, Reactor Recirculation System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Steel	Treated Water (Internal)	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2)	V.D2.EP-60	3.2-1, 016	A
Piping, piping components (Valve Body (Class 1))	Pressure Boundary	Steel	Treated Water (Internal)	Loss of material due to general, pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	V.D2.EP-60	3.2-1, 016	A

Table 3.1.2-4 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. Applicable environment has Closed-Cycle Cooling Water above 60 °C [>140 °F] which exceeds the threshold for SS SCC.

Table 3.1.2-5, Fuel Assemblies - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Fuel Assemblies	Not applicable	Not applicable	Not applicable	None	None	None	None	1

Table 3.1.2-5 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.

B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.

C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.

D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.

F. Material not in NUREG-2191 for this component.

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.

Plant Specific Notes

1. Fuel Assemblies are subject to replacement in accordance with the Core Reload Process. As such, they are short-lived components and not subject to aging management.

3.2 AGING MANAGEMENT OF ENGINEERED SAFETY FEATURES AND REACTOR CORE ISOLATION COOLING SYSTEM

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 and Reactor Core Isolation Cooling 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.

- Containment System (2.3.2.1)
- Standby Gas Treatment System (2.3.2.2)
- Reactor Core Isolation Cooling System (2.3.2.3)
- High Pressure Coolant Injection System (2.3.2.4)
- Residual Heat Removal System (2.3.2.5)
- Core Spray System (2.3.2.6)
- Containment Atmosphere Dilution System (2.3.2.7)

3.2.2 Results

The following tables summarize the results of the aging management review for Engineered Safety Features and Reactor Core Isolation Cooling System.

- Table 3.2.2-1 Containment System - Summary of Aging Management Evaluation
- Table 3.2.2-2 Standby Gas Treatment System - Summary of Aging Management Evaluation
- Table 3.2.2-3 Reactor Core Isolation System - Summary of Aging Management Evaluation
- Table 3.2.2-4 High Pressure Coolant Injection System - Summary of Aging Management Evaluation
- Table 3.2.2-5 Residual Heat Removal System - Summary of Aging Management Evaluation
- Table 3.2.2-6 Core Spray System - Summary of Aging Management Evaluation
- Table 3.2.2-7 Containment Atmosphere Dilution System - Summary of Aging Management Evaluation

3.2.2.1 Materials, Environments, Aging Effects Requiring Management And Aging Management Programs

3.2.2.1.1 Containment System

Materials

The materials of construction for the Containment System components are:

- Aluminum
- Copper alloy
- Elastomer
- Galvanized Steel
- High-strength Steel

- Glass
- Nickel alloy
- Polymeric
- Stainless Steel
- Steel

Environments

The Containment System components are exposed to the following environments:

- Air
- Air indoor uncontrolled
- Concrete
- Outdoor air
- Soil
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the Containment System components require management:

- Cracking
- Hardening or loss of strength
- Flow blockage due to fouling
- Loss of material
- Selective leaching
- Loss of preload
- Reduction of heat transfer
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Containment System components:

- Bolting Integrity (B.2.1.10)
- Buried and Underground Piping and Tanks (B.2.1.27)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Fire Protection (B.2.1.15)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- Water Chemistry (B.2.1.2)

3.2.2.1.2 Standby Gas Treatment System

Materials

The materials of construction for the Standby Gas Treatment System components are:

- Aluminum
- Steel
- Copper alloy
- Elastomer
- Polymeric
- Stainless steel

Environments

The Standby Gas Treatment System components are exposed to the following environments:

- Air
- Air indoor controlled
- Air indoor uncontrolled
- Gas
- Soil

Aging Effects Requiring Management

The following aging effects associated with the Standby Gas Treatment System components require management:

- Cracking
- Flow blockage due to fouling
- Hardening or loss of strength
- Loss of preload
- Loss of material

Aging Management Programs

The following aging management programs manage the aging effects for the Standby Gas Treatment System components:

- Bolting Integrity (B.2.1.10)
- Buried and Underground Piping and Tanks (B.2.1.27)
- One-Time Inspection (B.2.1.20)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)

3.2.2.1.3 Reactor Core Isolation Cooling System

Materials

The materials of construction for the Reactor Core Isolation Cooling System components are:

- Aluminum
- Copper alloy
- Copper alloy (>15% Zn or >8% Al)
- Glass
- Gray cast iron
- Steel
- Stainless steel

Environments

The Reactor Core Isolation Cooling System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Gas
- Lubricating oil
- Reactor coolant
- System temperature up to 288°C (550°F)
- Treated water
- Treated water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects associated with the Reactor Core Isolation Cooling System components require management:

- Cracking
- Cumulative fatigue damage
- Loss of material
- Selective leaching
- Loss of preload
- Reduction of heat transfer due to fouling
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Core Isolation Cooling System components:

- ASME Code Class 1 Small-Bore Piping (B.2.1.22)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- Bolting Integrity (B.2.1.10)

- BWR Stress Corrosion Cracking (B.2.1.5)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Lubricating Oil Analysis (B.2.1.25)
- Selective Leaching (B.2.1.21)
- One-Time Inspection (B.2.1.20)
- Water Chemistry (B.2.1.2)
- Fatigue Monitoring (B.3.1.1)
- TLAA (Section 4.3)

3.2.2.1.4 High Pressure Coolant Injection System

Materials

The materials of construction for the High Pressure Coolant Injection System components are:

- Steel
- Copper Alloy
- Copper alloy (>15% Zn or >8% Al)
- Glass
- Gray Cast Iron
- High-strength Steel
- Nickel alloy
- Polymeric
- Stainless Steel

Environments

The High Pressure Coolant Injection System components are exposed to the following environments:

- Air
- Air - Indoor Uncontrolled
- Closed-cycle cooling water
- Condensation
- Lubricating Oil
- Reactor coolant
- Steam
- System temperature up to 288°C (550°F)
- Treated Water
- Treated Water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects associated with the High Pressure Coolant Injection System components require management:

- Cracking
- Cumulative fatigue damage
- Hardening or loss of strength
- Long-term loss of material
- Loss of material
- Loss of preload
- Loss of material due to selective leaching
- Reduction of heat transfer
- Wall thinning due to flow-accelerated corrosion

Aging Management Programs

The following aging management programs manage the aging effects for the High Pressure Coolant Injection System components:

- ASME Code Class 1 Small-Bore Piping (B.2.1.22)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Flow- Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Lubricating Oil Analysis (B.2.1.25)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- Water Chemistry (B.2.1.2)
- TLAA (Section 4.3)

3.2.2.1.5 Residual Heat Removal System

Materials

The materials of construction for the Residual Heat Removal System components are:

- Aluminum
- Cast austenitic stainless steel
- Copper alloy
- Copper alloy (>15% Zn or >8% Al)
- Gray cast iron
- High-strength Steel
- Metallic

- Stainless steel
- Steel

Environments

The Residual Heat Removal System components are exposed to the following environments:
- Air
- Air - indoor uncontrolled
- Air - outdoor
- Closed-cycle cooling water >60°C (>140°F)
- Lubricating Oil
- Reactor coolant
- Treated water
- Treated water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects associated with the Residual Heat Removal System components require management:
- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of fracture toughness
- Loss of material
- Loss of preload
- Flow blockage due to fouling
- Selective leaching
- Reduction of heat transfer due to fouling
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Residual Heat Removal System components:
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- ASME Code Class 1 Small-Bore Piping (B.2.1.22)
- Bolting Integrity (B.2.1.10)
- BWR Stress Corrosion Cracking (B.2.1.5)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Flow-Accelerated Corrosion (B.2.1.9)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)

- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- Water Chemistry (B.2.1.2)
- Lubricating Oil Analysis (B.2.1.25)
- TLAA (Section 4.3)

3.2.2.1.6 Core Spray System

Materials

The materials of construction for the Core Spray System components are:

- Aluminum
- Cast austenitic stainless steel
- Gray cast iron
- High-strength steel
- Polymeric
- Stainless steel
- Steel
- Steel (with or without nickel alloy or stainless steel cladding)

Environments

The Core Spray System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Gas
- Lubricating Oil
- Reactor coolant
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the Core Spray System components require management:

- Cracking
- Cumulative fatigue damage
- Flow blockage due to fouling
- Hardening or loss of strength
- Long-term loss of material
- Loss of fracture toughness
- Loss of material
- Loss of preload
- Selective leaching
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Core Spray System components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- ASME Code Class 1 Small-Bore Piping (B.2.1.22)
- Bolting Integrity (B.2.1.10)
- BWR Stress Corrosion Cracking (B.2.1.5)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- Water Chemistry (B.2.1.2)
- Flow-Accelerated Corrosion (B.2.1.9)
- Lubricating Oil Analysis (B.2.1.25)
- TLAA (Section 4.3)

3.2.2.1.7 Containment Atmosphere Dilution System

Materials

The materials of construction for the Containment Atmosphere Dilution System components are:

- Aluminum
- Copper alloy
- High-strength steel
- Stainless steel
- Steel

Environments

The Containment Atmosphere Dilution System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air - outdoor
- Gas
- Soil, concrete

Aging Effects Requiring Management

The following aging effects associated with the Containment Atmosphere Dilution System components require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the Containment Atmosphere Dilution System components:

- Bolting Integrity (B.2.1.10)
- Buried and Underground Piping and Tanks (B.2.1.27)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- One-Time Inspection (B.2.1.20)

3.2.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL-SLR Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the subsequent license renewal application. For the Engineered Safety Features and Reactor Core Isolation Cooling System, those programs are addressed in the following subsections.

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.

Table 3.2.1 Item Number 3.2-1, 001: This item evaluates stainless steel and steel piping, piping components exposed to any environment for cumulative fatigue damage due to fatigue. Cumulative fatigue damage of steel and stainless steel piping, piping components is evaluated and dispositioned as a TLAA for the High Pressure Coolant Injection System, Reactor Core Isolation Cooling System, and Residual Heat Removal System as discussed in Section 4.3.

3.2.2.2.2 Loss of Material Due to Pitting and Crevice Corrosion in Stainless Steel and Nickel Alloys

Loss of material due to pitting and crevice corrosion could occur in indoor or outdoor stainless steel (SS) and nickel alloy piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components; or (d) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS and nickel alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS and *nickel alloy components, rain and changing weather conditions can result in moisture intrusion into the insulation.*

Plant-specific operating experience (OE) and the condition of SS and nickel alloy components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for SS and nickel alloy components if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion, and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel alloy piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that affects the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of systems, structures, and components (SSCs), the following AMPs describe acceptable programs to manage loss of material due to pitting or crevice corrosion: (a) the GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) the GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) the GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) the GALL-SLR Report AMP XI.M38, 'Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, a one-time inspection would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

The applicant may establish that loss of material due to pitting and crevice corrosion is not an aging effect requiring management by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.

<u>Table 3.2.1 Item Numbers 3.2-1, 004 and 3.2-1, 048:</u> These items evaluate loss of material due to pitting and crevice corrosion in stainless steel and nickel alloy piping, piping components, and tanks exposed to air or condensation environments. There are stainless steel or nickel alloy piping, piping components, or tanks exposed to the air-outdoor or air-indoor controlled environments in the ESF and RCIC Systems. There are no nickel alloy tanks in the ESF and RCIC Systems. Plant-specific operating experience (OE) associated with stainless steel and

nickel alloy components in the ESF and RCIC Systems has been evaluated to determine if prolonged exposure to the air-outdoor or air-indoor uncontrolled and condensation environments has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at BFN for stainless steel or nickel alloy components in these environments, or as a result of transportable halogens, indicating that these environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in loss of material. Accordingly, the One-Time Inspection program (B.2.1.20) will be implemented to demonstrate that the aging effect of loss of material is not occurring in stainless steel piping, piping components, and tanks exposed to the air-outdoor or air-indoor uncontrolled and condensation environments. The One-Time Inspection program will also be implemented to demonstrate that the aging effect of loss of material is not occurring in nickel alloy piping and piping components exposed to the air-outdoor or air- indoor uncontrolled and condensation environments. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection program (B.2.1.20) is described in Appendix B.

Table 3.2.1 Item Number 3.2-1, 099: Not applicable. There are no stainless steel or nickel alloy tanks exposed to air or condensation in the ESF and RCIC Systems.

Table 3.2.1 Item Number 3.2-1, 106: Not applicable. There are no stainless steel or nickel alloy tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) in the ESF and RCIC Systems.

Table 3.2.1 Item Number 3.2-1, 107: Not applicable. There are no insulated stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation in the ESF and RCIC Systems.

Table 3.2.1 Item Number 3.2-1, 112: Not applicable. There are no stainless steel or nickel alloy underground piping, piping components, or tanks in the ESF and RCIC Systems.

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.

Table 3.2.1 Item Number 3.2-1, 006: This item evaluates loss of material due to general, pitting, and crevice corrosion and flow blockage due to fouling of metallic drywell and suppression chamber spray nozzles exposed to air-indoor uncontrolled and condensation environments. The BFN Units 1, 2, and 3 drywell and suppression chamber spray nozzles within the Residual Heat Removal System are copper alloy with greater than 15 percent zinc and are exposed to a condensation internal environment. The Residual Heat Removal System carbon steel piping sections downstream of the inboard primary containment motor operated isolation valves up to the drywell and suppression chamber spray nozzles are normally dry and subject to wetting, but are periodically wetted only during transient or accident conditions that require drywell or suppression chamber spray operation. Loss of material is not an aging effect for copper alloys in a condensation environment. Since the upstream piping is carbon steel, flow blockage due to fouling is an applicable aging effect for the spray nozzles.

When the piping between the drywell spray inboard and outboard primary containment isolation valves is filled with water to support inservice testing of valves, that piping is drained prior to opening the inboard isolation valve to preclude water flow into the downstream piping towards the spray header, and to maintain the piping between the isolation valves and the downstream piping to the spray header dry. During inservice testing of the primary containment isolation valves associated with the suppression chamber spray, the piping configuration and sequence of valve testing precludes the piping downstream of the inboard primary containment isolation valve from being wetted. When the piping between suppression chamber spray inboard and outboard primary containment isolation valves is filled with water to support inservice testing of pumps and valves, any leakage past the inboard primary containment isolation valve during testing drains to the suppression chamber via the spray nozzles due to the piping configuration to maintain the piping downstream of the inboard isolation valve dry.

Plant-specific OE has revealed corrosion on the carbon steel nipple between the header and a BFN Unit 2 torus spray copper alloy nozzle. The corrosion was attributed to leakage in the upstream valves that created a prolonged wetted condition. This leakage created a non-typical environment for the nozzle and piping. The corrective actions were to repair the upstream valves to eliminate the leakage. An engineering evaluation determined there was no degradation to the carbon steel nipple and no blockage resulting from the corrosion. The BFN surveillance procedure for the torus (suppression pool) nozzle test was successfully performed after discovery of the condition which validated no flow blockage existed at this nozzle. A verification of air or water flow through each drywell and suppression chamber spray nozzle is also performed periodically to satisfy Technical Specification surveillance requirements. Based on confirmation of no flow blockage after discovery and the repair to the leaking valve bringing the environment into conformance with the GALL/SRP item, the One-Time Inspection program (B.2.1.20) is sufficient and will be implemented to manage the aging effects of flow blockage due to fouling for the drywell and suppression chamber spray nozzles. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection program (B.2.1.20) is described in Appendix B.

3.2.2.2.4 Cracking Due to Stress Corrosion Cracking in Stainless Steel Alloys

Cracking due to stress corrosion cracking (SCC) could occur in indoor or outdoor SS piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components, or (d) in the vicinity of potentially transportable halogens. Cracking can occur in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS components exposed to indoor air, outdoor air, condensation, or underground environments are susceptible to SCC if the insulation contains certain contaminants. Leakage of fluids through bolted connections (e.g., flanges, valve packing) can result in contaminants present in the insulation leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific OE and the condition of SS components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in SCC. SCC in SS components is not an aging effect requiring management if (a) plant-specific OE does not reveal a history of SCC and (b) a one-time inspection demonstrates that the aging effect is not occurring.

In the environment of air-indoor controlled, SCC is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations. The applicant documents the results of the plant-specific OE review in the SLRA.

The GALL-SLR Report recommends further evaluation of SS piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of SCC. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that SCC is not occurring. If SCC is applicable, the following AMPs describe acceptable programs to manage loss of material due to SCC: (a) the GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) the GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) the GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) the GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

The applicant may establish that SCC is not an aging effect requiring management for all components, by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.

Table 3.2.1 Item Number 3.2-1, 007: This item evaluates cracking due to SCC in stainless steel piping, piping components, and tanks exposed to air and condensation environments. There are stainless steel piping, piping components, or tanks exposed to the air-indoor controlled or air-outdoor environments in the ESF and RCIC Systems. Plant-specific OE associated with stainless steel components in the ESF and RCIC Systems has been evaluated to determine if prolonged exposure to the air-indoor uncontrolled or air-outdoor and condensation environments has resulted in cracking due to SCC. Cracking has not been identified as an aging effect at BFN for stainless steel components in these environments, or as a result of transportable halogens, indicating that the environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in SCC. Accordingly, the One-Time Inspection program (B.2.1.20) will be implemented to demonstrate that the aging effect of cracking is not occurring in stainless steel piping, piping components, and tanks exposed to air-indoor uncontrolled and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection program (B.2.1.20) is described in Appendix B.

Table 3.2.1 Item Number 3.2-1, 080: Not applicable. There are no stainless steel underground piping, piping components, or tanks in the ESF and RCIC Systems.

Table 3.2.1 Item Number 3.2-1, 103: Not applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) in the ESF and RCIC Systems.

Table 3.2.1 Item Number 3.2-1, 108: Not applicable. There are no insulated stainless steel piping, piping components, tanks exposed to air, condensation in the ESF and RCIC Systems.

3.2.2.2.5 Quality Assurance for Aging Management of Nonsafety-Related Components

QA provisions applicable to Subsequent License Renewal are discussed in Appendix A, Section A.1.4, and Appendix B, Section B.1.3.

3.2.2.2.6 Ongoing Review of Operating Experience

Ongoing review of operating experience is addressed in Appendix A, Section A.1.5, and Appendix B, Section B.1.4.

3.2.2.2.7 Loss of Material Due to Recurring Internal Corrosion

Recurring internal corrosion can result in the need to augment AMPs beyond the recommendations in the GALL-SLR Report. During the search of plant-specific OE conducted during the SLRA development, recurring internal corrosion can be identified by the number of occurrences of aging effects and the extent of degradation at each localized corrosion site. This further evaluation item is applicable if the search of plant-specific OE reveals repetitive occurrences. The criteria for recurrence is (a) a 10-year search of plant-specific OE reveals the aging effect has occurred in three or more refueling outage cycles; or (b) a 5-year search of plant-specific OE reveals the aging effect has occurred in two or more refueling outage cycles and resulted in the component either not meeting plant-specific acceptance criteria or experiencing a reduction in wall thickness greater than 50 percent (regardless of the minimum wall thickness).

The GALL-SLR Report recommends that the GALL-SLR Report AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,” be evaluated for inclusion of augmented requirements to ensure the adequate management of any recurring aging effect(s). Alternatively, a plant-specific AMP may be proposed. Potential augmented requirements include: alternative examination methods (e.g., volumetric versus external visual), augmented inspections (e.g., a greater number of locations, additional locations based on risk insights based on susceptibility to aging effect and consequences of failure, a greater frequency of inspections), and additional trending parameters and decision points where increased inspections would be implemented.

The applicant states: (a) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (b) the basis for the adequacy of augmented or lack of augmented inspections, (c) what *parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (d) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (e) how leaks in any involved buried or underground components will be identified.*

Plant-specific OE examples should be evaluated to determine if the chosen AMP should be augmented even if the thresholds for significance of aging effect or frequency of occurrence of aging effect have not been exceeded. For example, during a 10-year search of plant-specific OE, two instances of a 360 degree 30 percent wall loss occurred at copper alloy to steel joints. Neither the significance of the aging effect nor the frequency of occurrence of aging effect threshold has been exceeded. Nevertheless, the OE should be evaluated to determine if the AMP that is proposed to manage the aging effect is sufficient (e.g., method of inspection, frequency of inspection, number of inspections) to provide reasonable assurance that the current licensing basis (CLB) intended functions of the component will be met throughout the subsequent period of extended operation. While recurring internal corrosion is not as likely in other environments as raw water and waste water (e.g., treated water), the aging effect should be addressed in a similar manner.

<u>Table 3.2.1 Item Number 3.2-1, 066:</u> This item evaluates loss of material due to recurring internal corrosion of metallic piping, piping components, and tanks exposed to raw water and waste water. There are no components exposed to raw water in the ESF and RCIC Systems. The cooling water side of the RHR Heat Exchanger is exposed to raw water and is addressed in the subsection 3.3.2.2.7.

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.

<u>Susceptible Material:</u> If the material is not susceptible to SCC, then cracking is not an aging effect requiring management. The microstructure of an aluminum alloy, of which alloy composition is only one factor, is what determines if the alloy is susceptible to SCC. Therefore, determining susceptibility based on alloy composition alone is not adequate to conclude whether a particular material is susceptible to SCC. The temper, condition, and product form of the alloy is considered when assessing if a material is susceptible to SCC. Aluminum alloys that are susceptible to SCC include:

- *2xxx series alloys in the F, W, Ox, T3x, T4x, or T6x temper*
- *5xxx series alloys with a magnesium content of 3.5 weight percent or greater*
- *6xxx series alloys in the F temper*
- *7xxx series alloys in the F, T5x, or T6x temper*
- *2xx.x and 7xx.x series alloys*

- *3xx.x series alloys that contain copper*
- *5xx.x series alloys with a magnesium content of greater than 8 weight percent*

The material is evaluated to verify that it is not susceptible to SCC and that the basis used to make the determination is technically substantiated. Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combination which are not susceptible to SCC when used in piping, piping component, and tank applications include 1xxx series, 3xxx series, 6061-T6x, and 5454-x. If it is determined that a material is not susceptible to SCC, the SLRA provides the components/locations where it is used, alloy composition, temper or condition, product form, and for tempers not addressed above, the basis used to determine the alloy is not susceptible and technical information substantiating the basis.

<u>Aggressive Environment:</u> If the environment to which an aluminum alloy is exposed is not aggressive, such as dry gas or treated water, then cracking due to SCC will not occur and it is not an aging effect requiring management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys are aqueous solutions, air, condensation, and underground locations that contain halides (e.g., chloride). Halide concentrations should be considered high enough to facilitate SCC of aluminum alloys in uncontrolled or untreated aqueous solutions and air, such as raw water, waste water, condensation, underground locations, and outdoor air, unless demonstrated otherwise.

Halides could be present on the surface of the aluminum material if the component is encapsulated in a material such as insulation or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, sufficient halide concentrations to cause SCC could be present due to secondary sources such as leakage from nearby components (e.g., leakage from insulated flanged connections or valve packing). If an aluminum component is exposed to a halide-free indoor air environment, not encapsulated in materials containing halides, and the exposure to secondary sources of moisture or halides is precluded, cracking due to SCC is not expected to occur. The plant-specific configuration can be used to demonstrate that exposure to halides will not occur. If it is determined that SCC will not occur because the environment is not aggressive, the SLRA provides the components and locations exposed to the environment, a description of the environment, basis used to determine the environment is not aggressive, and technical information substantiating the basis. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," and a review of plant-specific OE describe an acceptable means to confirm the absence of moisture or halides within the proximity of the aluminum component.

If the environment potentially contains halides, the GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," describes an acceptable program to manage cracking due to SCC of aluminum tanks. The GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking due to SCC of aluminum piping and piping components. The GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage cracking due to SCC of aluminum piping and tanks, which are buried or underground. The GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," describes an acceptable program to manage cracking due to SCC of aluminum components that are not included in other AMPs.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent SCC. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to *aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.*

Table 3.2.1 Item Number 3.2-1, 100: This item evaluates cracking due to SCC in aluminum piping, piping components, tanks exposed to air, condensation (internal), raw water and waste water. There are aluminum piping, piping components, tanks exposed to the air-indoor controlled or air-outdoor environments in the ESF and RCIC Systems. There are no aluminum piping, piping components, tanks with internal coatings/linings exposed to the air-indoor controlled or air-outdoor environments in the ESF and RCIC Systems. Plant-specific OE associated with aluminum components in the ESF and RCIC Systems has been evaluated to determine if prolonged exposure to the air, condensation, raw water, and waste water environments has resulted in cracking due to SCC. Cracking has not been identified as an aging effect at BFN for aluminum components in these environments, or as a result of transportable halogens, indicating that the environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in SCC. Accordingly, the One-Time Inspection program (B.2.1.20) will be implemented to demonstrate that the aging effect of cracking is not occurring in aluminum piping, piping components, tanks exposed to air, condensation (internal), raw water and waste water. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection program (B.2.1.20) is described in Appendix B.

Table 3.2.1 Item Number 3.2-1, 101: This item evaluates cracking due to SCC in aluminum piping, piping components and tanks exposed to air, condensation (external). There are aluminum piping, piping components, tanks exposed to the air-indoor controlled or air-outdoor environments in the ESF and RCIC Systems. There are no aluminum piping, piping components, tanks with internal coatings/linings exposed to the air-indoor controlled or air-outdoor environments in the ESF and RCIC Systems. Plant-specific OE associated with aluminum components in the ESF and RCIC Systems has been evaluated to determine if prolonged exposure to the air condensation environments has resulted in cracking due to SCC. Cracking has not been identified as an aging effect at BFN for aluminum components in these environments, or as a result of transportable halogens, indicating that the environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in SCC. Accordingly, the One-Time Inspection program (B.2.1.20) will be implemented to demonstrate that the aging effect of cracking is not occurring in aluminum piping, piping components, tanks exposed to air and condensation (external). Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection program (B.2.1.20) is described in Appendix B.

Table 3.2.1 Item Number 3.2-1, 102: Not applicable. There are no aluminum alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") in the ESF and RCIC Systems.

Table 3.2.1 Item Number 3.2-1, 109: Not applicable. There are no insulated aluminum alloy piping, piping components, or tanks in the ESF and RCIC Systems.

Table 3.2.1 Item Number 3.2-1, 110: Not applicable. There are no aluminum alloy underground piping, piping components, or tanks in the ESF and RCIC 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.

Table 3.2.1 Item Numbers 3.2-1, 055: Carbon steel piping, piping components exposed to concrete in the Standby Gas Treatment System and Containment System is potentially exposed to groundwater, therefore loss of material is considered to be an applicable aging effect. Loss of material is managed by the Buried and Underground Piping and Tanks program (B.2.1.27) and is addressed by Item Number 3.2.1, 052.

Table 3.2.1 Item Number 3.2-1, 091: Not applicable. There are no stainless steel piping or piping components exposed to concrete in the ESF and RCIC Systems.

3.2.2.2.10 Loss of Material Due to Pitting and Crevice Corrosion in Aluminum Alloys

Loss of material due to pitting and crevice corrosion could occur in aluminum piping, piping components, and tanks exposed to an air, condensation, underground, raw water, or waste water environment for a sufficient duration of time. Environments that can result in pitting and/or crevice corrosion of aluminum alloys are those that contain halides (e.g., chloride) in the presence of moisture. The moisture level and halide concentration in atmospheric and uncontrolled air are greatly dependent on geographical location and site-specific conditions. Moisture level and halide concentration should be considered high enough to facilitate pitting and/or crevice corrosion of aluminum alloys in atmospheric and uncontrolled air, unless demonstrated otherwise. The periodic introduction of moisture or halides into an environment from secondary sources should also be considered. Leakage of fluids from mechanical connections (e.g., insulated bolted flanges and valve packing); onto a component in indoor controlled air is an *example of a secondary source that should be considered. Halide concentrations should be considered high enough to facilitate loss of material of aluminum alloys in untreated aqueous solutions, unless demonstrated otherwise. Plant-specific OE and the condition of aluminum alloy components are evaluated to determine if prolonged exposure to the plant-specific air, condensation, underground, or water environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for aluminum alloys if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components. The applicant documents the results of the plant-specific OE review in the SLRA.*

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Alloy susceptibility may be considered when reviewing OE and interpreting inspection results. Inspections focus on the most susceptible alloys and locations.

The GALL-SLR Report recommends the further evaluation of aluminum piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting and crevice corrosion: (i) the GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (ii) the GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components,' for external surfaces of piping and piping components; (iii) the GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (iv) the GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent loss of material due to pitting and crevice corrosion. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," or equivalent program, describes an acceptable program to manage the integrity of a barrier coating.

<u>Table 3.2.1 Item Number 3.2-1, 042:</u> This item evaluates loss of material due to pitting and crevice corrosion in aluminum alloy piping, piping components, and tanks exposed to air or condensation external environments. There are no aluminum alloy tanks in the ESF and RCIC Systems. There are aluminum alloy piping or piping components exposed to the air-indoor controlled, air-outdoor, or condensation external environments in the ESF and RCIC Systems. Plant-specific OE associated with aluminum alloy components in the ESF and RCIC Systems has been evaluated to determine if prolonged exposure to air-indoor uncontrolled environment

has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at BFN for aluminum alloy components in this environment, or as a result of transportable halogens, indicating that this environment does not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in loss of material. Accordingly, the One-Time Inspection program (B.2.1.20) will be implemented to demonstrate that the aging effect of loss of material is not occurring in aluminum piping, piping components exposed to air-indoor uncontrolled. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection program (B.2.1.20) is described in Appendix B.

Table 3.2.1 Item Number 3.2-1, 056: This item evaluates loss of material due to pitting, crevice corrosion in aluminum piping, piping components, tanks exposed to air, condensation (internal). There are aluminum alloy piping, piping components, or tanks exposed to internal air or condensation environments in the ESF and RCIC Systems. Plant-specific OE associated with aluminum alloy components in the ESF and RCIC Systems has been evaluated to determine if prolonged exposure to air-indoor uncontrolled environment has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at BFN for aluminum alloy components in this environment, or as a result of transportable halogens, indicating that this environment does not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in loss of material. Accordingly, the One-Time Inspection program (B.2.1.20) will be implemented to demonstrate that the aging effect of loss of material is not occurring in aluminum piping, piping components exposed to air-indoor uncontrolled. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection program (B.2.1.20) is described in Appendix B.

Table 3.2.1 Item Number 3.2-1, 105: Not applicable. There are no aluminum alloy tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) in the ESF and RCIC Systems.

Table 3.2.1 Item Number 3.2-1, 111: Not applicable. There are no aluminum alloy underground piping, piping components, or tanks in the ESF and RCIC Systems.

Table 3.2.1 Item Number 3.2-1, 119: Not applicable. There are no insulated aluminum piping, piping components, tanks exposed to air, condensation in the ESF and RCIC Systems.

Table 3.2.1 Item Number 3.2-1, 121: Not applicable. There are no aluminum alloy piping, piping components, or tanks exposed to raw water or waste water in the ESF and RCIC Systems.

3.2.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Engineered Safety Features and Reactor Core Isolation Cooling System components:

- Section 4.3, Metal Fatigue Analyses
  - Section 4.3.2, Metal Fatigue of Class 1 Components
  - Section 4.3.4, Metal Fatigue of Non-Class 1 Components
  - Section 4.3.5, Environmental Fatigue Analyses for Reactor Vessel and Class 1 Piping
- Section 4.6, Primary Containment Fatigue Analyses
  - Section 4.6.1, Suppression Chambers, Vents and Downcomers

- Section 4.6.2, Torus Attached Piping and Safety Relief Valve Discharge Lines
- Section 4.6.3, Containment Vent Lines and Process Penetration Bellows

3.2.3 Conclusion

The Engineered Safety Features components that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Engineered Safety Features and Reactor Core Isolation Cooling System components are identified in the summaries in Section 3.2.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the subsequent period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Engineered Safety Features and Reactor Core Isolation Cooling components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the current licensing basis during the subsequent period of extended operation.

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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	Fatigue is a TLAA; further evaluation is documented in Section 4.3.
3.2-1, 002	This Item Number is not used in NUREG-2192.				
3.2-1, 003	This Item Number is not used in NUREG-2192.				
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage loss of material of the nickel alloy and stainless steel piping, piping components, and tanks exposed to air - indoor uncontrolled and condensation in the Containment Atmosphere Dilution System, Core Spray System, High Pressure Coolant Injection System, Containment System, Reactor Core Isolation Cooling System, Residual Heat Removal System and Standby Gas Treatment System. See Subsection 3.2.2.2.2.
3.2-1, 005	PWR Only				

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will beused to manage loss of material due to general, pitting, crevice corrosion; flow blockage due tofouling of the copper alloy spray nozzles exposed to condensation in the Residual Heat Removal System. Plant-specific OE has revealed corrosion in the carbon steel nipple between the header and a BFN Unit 2 torus spray copper alloy nozzle. The corrosion was attributed to leakage in the upstream valves that created a prolonged wetted condition. An engineering evaluation determined there was no degradation to the carbon steel nipple and no blockage resulting from the corrosion. The BFN surveillance procedure for the torus (suppression pool) nozzle test was successfully performed after discovery of the condition which validated no flow blockage existed at this nozzle. Therefore, the One-Time Inspection (B.2.1.20) program will be implemented to manage Loss of material due to general, pitting, crevice corrosion; flow blockage due to fouling. See Subsection 3.2.2.2.3.

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage cracking of the stainless steel heat exchanger components, piping, piping components, and tanks exposed to air - indoor uncontrolled and condensation in the Containment Atmosphere Dilution System, Core Spray System, High Pressure Coolant Injection System, Containment System, Reactor Core Isolation Cooling System, Residual Heat Removal System, Standby Gas Treatment System, Reactor Vessel and Reactor Recirculation System. See Subsection 3.2.2.2.4.
3.2-1, 008	PWR Only				
3.2-1, 009	PWR Only				
3.2-1, 010	Cast austenitic stainless steel piping, piping components exposed to treated borated water >250°C (>482°F), treated water >250°C (>482°F)	Loss of fracture toughness due to thermal aging embrittlement	AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)"	No	Consistent with NUREG-2191. The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program (B.2.1.8) will be used to manage loss of fracture toughness of cast austenitic stainless steel piping, piping components exposed to treated water > 482 F in the Reactor Recirculation System.
3.2-1, 011	Steel piping, piping components exposed to steam, treated water	Wall thinning due to flow-accelerated corrosion	AMP XI.M17, "Flow-Accelerated Corrosion"	No	Consistent with NUREG-2191. The Flow-Accelerated Corrosion program (B.2.1.9) will be used to manage wall thinning of the carbon steel piping, piping components exposed to steam and treated water in the Core Spray System, High Pressure Coolant Injection System, Reactor Core Isolation Cooling System and Residual Heat Removal System.

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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	Consistent with NUREG-2191. The Bolting Integrity program (B.2.1.10) will be used to manage Cracking due to SCC; cyclic loading of the high-strength steel closure bolting exposed to air, soil, underground in the Containment Atmosphere Dilution System, Core Spray System, High Pressure Coolant Injection System, Containment System, Standby Gas Treatment System, Reactor Core Isolation Cooling System, Residual Heat Removal System.
3.2-1, 013	This Item Number is not used in NUREG-2192.				
3.2-1, 014	Stainless steel, steel, nickel alloy closure bolting exposed to air- indoor uncontrolled, air-outdoor, condensation	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M18, "Bolting Integrity"	No	Consistent with NUREG-2191. The Bolting Integrity program (B.2.1.10) will be used to manage loss of material of the carbon and low alloy steel and stainless steel closure bolting exposedto air - indoor uncontrolled and air - outdoor in the Containment Atmosphere Dilution System, Core Spray System, High Pressure Coolant Injection System, Containment System, Standby Gas Treatment System, Reactor Core Isolation Cooling System, Residual Heat Removal System.

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2-1, 015	Metallic closure bolting exposed to any environment, soil underground	Loss of preload due to thermal effects, gasket creep, self- loosening	AMP XI.M18, “Bolting Integrity“	No	Consistent with NUREG-2191. The Bolting Integrity program (B.2.1.10) will be used to manage loss of preload of the carbon and low alloy steel and stainless steel closure bolting exposed to air - indoor uncontrolled, air - outdoor, and treated water in the Containment Atmosphere Dilution System, Core Spray System, High Pressure CoolantInjection System, Containment System, Standby Gas Treatment System, Reactor Core Isolation Cooling System and Residual Heat Removal System.
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) and Water Chemistry program (B.2.1.2) will be used to manage loss of material of the carbon steel and gray cast iron heat exchanger components, piping, piping components, and tanks exposed to reactor coolant, steam, and treated water in the Core Spray System, High Pressure Coolant Injection System, Containment System, Reactor Core Isolation Cooling System, Residual Heat Removal System, Reactor Vessel and Reactor Recirculation system.
3.2-1, 017	Aluminum piping, piping components exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion	AMP XI.M2, “Water Chemistry,” and AMP XI.M32, “One-Time Inspection”	No	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) and Water Chemistry program (B.2.1.2) will be used to manage loss of material of the aluminum piping, piping components exposed to treated water in the Core Spray System, Reactor Core Isolation Cooling System, Residual Heat Removal System.
3.2-1, 018	This Item Number is not used in NUREG-2192.				

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2-1, 019	Stainless steel heat exchanger tubes exposed to treated water, treated borated water	Reduction of heat transfer due to fouling	AMP XI.M2, “Water Chemistry” and AMP XI.M32, “One-Time Inspection”	No	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) and Water Chemistry program (B.2.1.2) will be used to manage reduction of heat transfer of the stainless steel heat exchanger components exposed to treated water in the Residual Heat Removal System.
3.2-1, 020	PWR Only				
3.2-1, 021	This Item Number is not used in NUREG-2192.				
3.2-1, 022	Nickel alloy, stainless steel heat exchanger components, piping, piping components, tanks exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, “Water Chemistry,” and AMP XI.M32, “One-Time Inspection”	No	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) and Water Chemistry program (B.2.1.2) will be used to manage loss of material of the stainless steel heat exchanger components and piping, piping components exposed to steam and treated water in the Core Spray System, High Pressure Coolant Injection System, Containment System, Reactor Core Isolation Cooling System, Residual Heat Removal System and Reactor Recirculation System.
3.2-1, 023	Steel heat exchanger components, piping, piping components exposed to raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, “Open-Cycle Cooling Water System”	No	Not Applicable. There are no stainless steel heat exchanger components, piping, piping components exposed to raw water in the ESF and RCIC Systems.
3.2-1, 024	PWR Only				

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2-1, 025	Stainless steel heat exchanger components exposed to raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, “Open-Cycle Cooling Water System”	No	Not Applicable. There are no stainless steel heat exchanger components exposed to raw water in the ESF and RCIC Systems.
3.2-1, 026	This Item Number is not used in NUREG-2192.				
3.2-1, 027	Stainless steel, steel heat exchanger tubes exposed to raw water	Reduction of heat transfer due to fouling	AMP XI.M20, “Open-Cycle Cooling Water System”	No	Not Applicable. There are no stainless steel heat exchanger tubes exposed to raw water in the ESF and RCIC Systems.
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	Consistent with NUREG-2191. The Closed Treated Water Systems program (B.2.1.12) will be used to manage cracking of the stainless steel piping, piping components exposed to closed cycle cooling water in the Residual Heat Removal System and Core Spray System.
3.2-1, 029	Steel piping, piping components exposed to closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, “Closed Treated Water Systems”	No	Not Applicable. There are no steel piping, piping components exposed to closed-cycle cooling water in ESF Systems or RCIC System
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	Not Applicable. There are no steel heat exchanger components exposed to closed cycle cooling water in ESF Systems or RCIC System.

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2-1, 031	Stainless steel heat exchanger components, piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, “Closed Treated Water Systems”	No	Consistent with NUREG-2191. The Closed Treated Water Systems program (B.2.1.12) will be used to manage loss of material of the stainless steel heat exchanger components exposed to closed cycle cooling water in the High Pressure Coolant Injection System and Reactor Recirculation System.
3.2-1, 032	Copper alloy heat exchanger components, piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, “Closed Treated Water Systems”	No	Not Applicable. There are no copper alloy heat exchanger components or piping, piping components exposed to closed cycle cooling water in ESF Systems or RCIC System.
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	Not Applicable. There are no copper alloy or stainless steel heat exchanger tubes exposed to closed cycle cooling water in ESF Systems or RCIC System.
3.2-1, 034	Copper alloy (>15% Zn or >8% Al) piping, piping components, heat exchanger components exposed to closed-cycle cooling water, treated water	Loss of material due to selective leaching	AMP XI.M33, “Selective Leaching”	No	Consistent with NUREG-2191. The Selective Leaching program (B.2.1.21) will be used to manage loss of material of the copper alloy with greater than 15% zinc heat exchanger components exposed to treated water in the High Pressure Coolant Injection System, Residual Heat Removal System, Reactor Core Isolation Cooling System and Reactor Recirculation System.
3.2-1, 035	PWR Only				
3.2-1, 036	PWR Only				

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2-1, 037	Gray cast iron, ductile iron piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, “Selective Leaching”	No	Not Applicable. There are no gray cast iron or ductile iron piping, piping components exposed to soil in ESF Systems or RCIC System.
3.2-1, 038	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	Not applicable. There are no elastomer piping, piping components, seals exposed to air, condensation in the ESF Systems or RCIC system.
3.2-1, 039	This Item Number is not used in NUREG-2192.				
3.2-1, 040	Steel external surfaces exposed to air – indoor uncontrolled, air – outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage loss of material of the carbon steel, ductile iron, and gray cast iron ducting and components, heat exchanger components, piping, piping components, and tanks exposed to air - indoor uncontrolled, and air - outdoor in the Containment Atmosphere Dilution System, Core Spray System, High Pressure Coolant Injection System, Containment System, Reactor Core Isolation Cooling System, Residual Heat Removal System and Standby Gas Treatment System.
3.2-1, 041	This Item Number is not used in NUREG-2192.				

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage loss of material of aluminum alloy piping, piping components exposed to air - indoor uncontrolled in the Reactor Coolant Core Isolation Cooling System and Containment Atmosphere Dilution System. See Subsection 3.2.2.2.10.
3.2-1, 043	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) will be used to manage hardening and loss of strength of elastomer ducting and components exposed to condensation in the Standby Gas Treatment System.
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. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) will be used to manage loss of material of the steel piping, piping components, ducting, ducting components exposed to air in the Containment Atmosphere Dilution System, Core Spray System, High Pressure Coolant Injection System, Containment System, Reactor Core Isolation Cooling System, Residual Heat Removal System and Standby Gas Treatment System.
3.2-1, 045	PWR Only				

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) will be used to manage loss of material of the carbon steel, galvanized steel, and gray cast iron ducting and components, heat exchanger components, piping, piping components, and tanks exposed to condensation in the High Pressure Coolant Injection System.
3.2-1, 047	PWR Only				
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage loss of material of the stainless steel piping, piping components, and tanks exposed to condensation in the High Pressure Coolant Injection System, Reactor Core Isolation Cooling System, Core Spray System and Residual Heat Removal System. See Subsection 3.2.2.2.2.
3.2-1, 049	Steel piping, piping components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, “Lubricating Oil Analysis,” and AMP XI.M32, “One-Time Inspection”	No	Consistent with NUREG-2191. The Lubricating Oil Analysis program (B.2.1.25) and One-Time Inspection program (B.2.1.20) will be used to manage loss of material of the carbon steel, ductile iron, and gray cast iron piping, piping components, and tanks exposed to lubricating oil in the High Pressure Coolant Injection System, Reactor Core Isolation Cooling System, Core Spray System and Reactor Recirculation System.

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2-1, 050	Copper alloy, stainless steel piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M39, “Lubricating Oil Analysis,” and AMP XI.M32, “One-Time Inspection”	No	Consistent with NUREG-2191. The Lubricating Oil Analysis program (B.2.1.25) and One-Time Inspection program (B.2.1.20) will be used to manage loss of material of the copper alloy and stainless steel piping, piping components exposed to lubricating oil in the Reactor Recirculation System.
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	Consistent with NUREG-2191. The Lubricating Oil Analysis program (B.2.1.25) and One-Time Inspection program (B.2.1.20) will be used to manage reduction of heat transfer of the copper alloy and stainless steel heat exchanger components exposed to lubricating oil in the High Pressure Coolant Injection System, and Reactor Core Isolation Cooling System.
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	Consistent with NUREG-2191 with exceptions. The Buried and Underground Piping and Tanks program (B.2.1.27) will be used to manage loss of material of the carbon steel piping, piping components exposed to concrete and soil in the Standby Gas Treatment System and Containment System. Exceptions apply to the NUREG-2191 recommendations for Buried and Underground Piping and Tanks program (B.2.1.27) implementation.

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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 with exceptions. The Buried and Underground Piping and Tanks program (B.2.1.27) will be used to manage loss of material of the stainless steel, nickel alloy piping, piping components, tanks, exposed to soil, concrete in the Containment Atmosphere Dilution System. Exceptions apply to the NUREG-2191 recommendations for Buried and Underground Piping and Tanks program (B.2.1.27) implementation.
3.2-1, 053a	This Item Number is not used in NUREG-2192.				
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	Cracking due to SCC in stainless steel piping, piping components greater than or equal to 4 NPS exposed to treated water >200 F in the Core Spray System, Reactor Core Isolation Cooling System, and Residual Heat Removal System is addressed by Item Number 3.1-1, 097.
3.2-1, 055	Steel piping, piping components exposed to concrete	None	None	Yes	Carbon steel piping, piping components exposed to concrete in the Standby GasTreatment System and Containment System is addressed by Item Number 3.2-1, 052. Consistent with NUREG-2191, there is no Aging Management Program required for the steel piping components exposed to concrete in the Containment System. See Subsection 3.2.2.2.9.

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2-1, 056	Aluminum piping, piping components, tanks exposed to air, condensation (internal)	Loss of material due to pitting, crevice corrosion	AMP XI.M32, “One-Time Inspection,” AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,” or AMP-XI.M42, “Internal Coatings/ Linings for In- Scope Piping, Piping Components, Heat Exchangers, and Tanks”	Yes	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage loss of material of the aluminum piping, piping components, and tanks exposed to air in the Containment System. See Subsection 3.2.2.2.10.
3.2-1, 057	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191, no Aging Management Program is required for copper alloy piping, piping components exposed to air, condensation or gas in the Containment Atmosphere Dilution System, Containment System, High Pressure Coolant Injection System, Reactor Core Isolation Cooling System, Residual Heat Removal System and Standby Gas Treatment System.
3.2-1, 058	PWR Only				
3.2-1, 059	Galvanized steel ducting, ducting components, piping, piping components exposed to air – indoor controlled	None	None	No	Consistent with NUREG-2191, no Aging Management Program is required for galvanized steel ducting, ducting components exposed to air in the Containment System and EHPM System.
3.2-1, 060	Glass piping elements exposed to air, underground, lubricating oil, raw water, treated water, treated borated water, air with borated water leakage, condensation, gas, closed-cycle cooling water	None	None	No	Consistent with NUREG-2191, there are no Aging Management Programs required for glass piping elements exposed to air, lubricating oil, or treated water for the Containment System, High Pressure Coolant Injection System, Reactor Core Isolation Colling System and Reactor Recirculation System.

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2-1, 061	This Item Number is not used in NUREG-2192.				
3.2-1, 062	Nickel alloy piping, piping components exposed to air with borated water leakage	None	None	No	Not Applicable. There are no nickel alloy piping, piping components exposed to air with borated water leakage in ESF Systems or RCIC System.
3.2-1, 063	Stainless steel piping, piping components exposed to air with borated water leakage, gas	None	None	No	Consistent with NUREG-2191, there are no Aging Management Programs required for stainless steel piping, piping components exposed to gas in the Containment Atmosphere Dilution System, Core Spray System, Reactor Core Isolation Cooling System and Standby Gas Treatment System.
3.2-1, 064	Steel piping, piping components exposed to air– indoor controlled, gas	None	None	No	Consistent with NUREG-2191, there are no Aging Management Programs required for steel piping, piping components exposed to gas in the Containment Atmosphere Dilution System and Standby Gas Treatment System.
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	Consistent with NUREG-2191. The Flow-Accelerated Corrosion program (B.2.1.9) will be used to manage wall thinning of thecarbon steel and stainless steel piping, piping components exposed to steam and treated water in the High Pressure Coolant Injection System, Reactor Core Isolation Cooling System, and Residual Heat Removal System.

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Not applicable. There are no metallic piping, piping components, tanks exposed to raw water, waste water in the ESF Systems or RCIC Systems. For BFN mechanical components are screened with the system in which they were scoped. For heat exchangers, the process side of the heat exchanger are evaluated with the process side system for aging management review. Likewise, the cooling water side of the heat exchanger is evaluated with the cooling waterside system for aging management review. Mechanical components exposed to raw water are addressed within the Section 3.3. See Subsection 3.2.2.2.7.
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	Not Applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to soil or concrete in ESF Systems or RCIC System.
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. There are no steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to soil, concrete, air, condensation for steel tanks in ESF Systems or RCIC System.

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage loss of material exposed to air, condensation for insulated steel piping, piping components and tanks in the Standby Gas Treatment System, High Pressure Coolant Injection System, Reactor Core Isolation Cooling System, and Residual Heat Removal System.
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	Not Applicable. There are no steel, stainless steel, or aluminum tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to treated water or treated borated water in ESF Systems or RCIC System.
3.2-1, 071	Insulated copper alloy (>15% Zn or >8% Al) piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	Not Applicable. There are no insulated copper alloy (>15% Zn or >8% Al) piping, piping components, or tanks exposed to air or condensation in ESF Systems or RCIC System.
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, lubrication oil, condensation	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage; loss of material or cracking for cementitious coatings/ linings	AMP XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks”	No	Not Applicable. There are no piping, piping components, heat exchangers, or tanks with internal coatings/ linings exposed to closed cycle cooling water, raw water, treated water, or treated borated water in ESF Systems or RCIC System.

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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, condensation	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks”	No	Not Applicable. There are no piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, treated water, treated borated water, lubricating oil, condensation in ESF Systems or RCIC System.
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. There are no gray cast iron or ductile iron piping, piping components with internal coatings/linings exposed to closed cycle cooling water, raw water, treated water, treated borated water, or waste water in ESF Systems or RCIC System.
3.2-1, 075	This Item Number is not used in NUREG-2192.				
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. The Bolting Integrity program (B.2.1.10) will be used to manage loss of material of the stainless steel closure bolting exposed to treated water in the Residual Heat Removal System.
3.2-1, 077	This Item Number is not used in NUREG-2192.				
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	Carbon steel piping, piping components exposed to concrete and soil in the Standby Gas Treatment System and Containment System is addressed by Item Number 3.2-1, 052.

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2-1, 079	Stainless steel closure bolting exposed to air, soil, concrete, underground	Cracking due to SCC	AMP XI.M18, “Bolting Integrity”	No	Consistent with NUREG-2191. The Bolting Integrity program (B.2.1.10) will be used to manage cracking of the stainless steel closure bolting exposed to air - indoor uncontrolled in the Containment System and Residual Heat Removal System.
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	Not Applicable. See Subsection 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. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage reduction of heat transfer due to fouling of the stainless steel, steel, aluminum copper alloy heat exchanger tubes exposed to air, condensation in the Reactor Core Isolation Cooling System, Containment System.
3.2-1, 082	This Item Number is not used in NUREG-2192.				
3.2-1, 083	This Item Number is not used in NUREG-2192.				
3.2-1, 084	This Item Number is not used in NUREG-2192.				
3.2-1, 085	This Item Number is not used in NUREG-2192.				
3.2-1, 086	This Item Number is not used in NUREG-2192.				

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2-1, 087	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage reduced thermal insulation resistance due to moisture intrusion of non-metallic thermal insulation, as shown in Table 3.5.2-36 Structural Commodities (Thermal Insulation), in the High Pressure Coolant Injection System, Reactor Core Isolation Cooling System, Standby Gas Treatment System and Residual Heat Removal System.
3.2-1, 088	This Item Number is not used in NUREG-2192.				
3.2-1, 089	This Item Number is not used in NUREG-2192.				
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage long-term loss of material of the carbon steel and gray cast iron heat exchanger components, piping, piping components, and tanks exposed to treated water in the Core Spray System, High Pressure Coolant Injection System, Reactor Core Isolation Cooling System and Residual Heat Removal System,
3.2-1, 091	Stainless steel piping, piping components exposed to concrete	None	None	Yes	Not Applicable. See Subsection 3.2.2.2.9.
3.2-1, 092	This Item Number is not used in NUREG-2192.				
3.2-1, 093	This Item Number is not used in NUREG-2192.				
3.2-1, 094	This Item Number is not used in NUREG-2192.				
3.2-1, 095	This Item Number is not used in NUREG-2192.				

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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. There are no steel or stainless steel piping, piping components exposed to raw water (for components not covered by NRC Generic Letter (GL) 89-13) in ESF Systems or RCIC System.
3.2-1, 097	This Item Number is not used in NUREG-2192.				
3.2-1, 098	Copper alloy (>15% Zn or >8% Al) piping, piping components exposed tosoil	Loss of material due to selective leaching	AMP XI.M33, “Selective Leaching”	No	Not Applicable. There are no copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil in ESF Systems or RCIC System.
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	Not Applicable. See Subsection 3.2.2.2.2.

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage cracking of the aluminum alloy piping, piping components exposed to air - indoor uncontrolled in the Standby Gas Treatment System. See Subsection 3.2.2.2.8.
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage cracking of the aluminum alloy piping, piping components exposed to air - indoor uncontrolled in the Containment Atmosphere Dilution System Standby Gas Treatment System and Residual Heat Removal System. See Subsection 3.2.2.2.8.
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	Not Applicable. See Subsection 3.2.2.2.8.

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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	Not Applicable. See Subsection 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. There are no aluminum tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to soil or concrete in ESF Systems or RCIC System.
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	Not Applicable. See Subsection 3.2.2.2.10.
3.2-1, 106	Stainless steel, nickel alloy tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks,” AMP XI.M32, “One-Time Inspection,” or AMP XI.M42, “Internal Coatings/Linings for In- Scope Piping, Piping Components, Heat Exchangers, and Tanks”	Yes	Not Applicable. See Subsection 3.2.2.2.2.

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2-1, 107	Insulated stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks,” AMP XI.M32, “One Time Inspection,” AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” or AMP XI.M42, “Internal Coatings/ Linings for In- Scope Piping, Piping Components, Heat Exchangers, and Tanks”	Yes	Not Applicable. See Subsection 3.2.2.2.2.
3.2-1, 108	Insulated stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks,” AMP XI.M32, “One Time Inspection,” AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” or AMP XI.M42, “Internal Coatings/ Linings for In- Scope Piping, Piping Components, Heat Exchangers, and Tanks”	Yes	Not Applicable. See Subsection 3.2.2.2.4.
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	Not Applicable. See Subsection 3.2.2.2.8.

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Not Applicable. See Subsection 3.2.2.2.8.
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	Not Applicable. See Subsection 3.2.2.2.10.
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	Not Applicable. See Subsection 3.2.2.2.2.
3.2-1, 113	This Item Number is not used in NUREG-2192.				
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) and Water Chemistry program (B.2.1.2) will be used to manage cracking of the stainless steel piping, piping components exposed to steam and treated water >140 F in the Reactor Coolant Isolation Cooling System, High Pressure Coolant Injection System, Residual Heat Removal System and, Reactor Recirculation System.

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. There are no titanium heat exchanger tubes exposed to treated water in ESF Systems or RCIC System.
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. There are no 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 ESF Systems or RCIC System.
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. There are no titanium heat exchanger tubes exposed to closed cycle cooling water in ESF Systems or RCIC System.
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. There are no 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 ESF Systems or RCIC System.

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2-1, 119	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks,” AMP XI.M32, “One-Time Inspection,” AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” or AMP XI.M42, “Internal Coatings/ Linings for In- Scope Piping, Piping Components, Heat Exchangers, and Tanks”	Yes	Not Applicable. See Subsection 3.2.2.2.10.
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. There are no aluminum piping, piping components, or tanks exposed to soil or concrete in ESF Systems or RCIC System.
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	Not Applicable. See Subsection 3.2.2.2.10.

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2-1, 122	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage loss of material of elastomer ducting components exposed to air - indoor uncontrolled in the Standby Gas Treatment System.
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. There are no elastomer piping, piping components, seals exposed to air in the ESF Systems or RCIC System.
3.2-1, 124	Aluminum piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not Applicable. There are no aluminum piping, piping components, or tanks exposed to air with borated water leakage in ESF Systems or RCIC System.
3.2-1, 125	Steel closure bolting exposed to soil, concrete, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, “Buried and Underground Piping and Tanks”	No	Not Applicable. There are no steel closure bolting exposed to soil, concrete, or underground in ESF Systems or RCIC System.
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. There are no titanium, super austenitic piping, piping components, tanks, or closure bolting exposed to soil, concrete, or underground in ESF Systems or RCIC System.
3.2-1, 127	Copper alloy piping, piping components exposed to concrete	None	None	No	Not Applicable. There are no copper alloy piping, piping components exposed to concrete in ESF Systems or RCIC System.

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. There are no copper alloy piping, piping components exposed to soil or underground in ESF Systems or RCIC System.
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	Not Applicable. There are no stainless steel tanks exposed to soil or concrete in ESF Systems or RCIC System.
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. The Lubricating Oil Analysis program (B.2.1.25) and One-Time Inspection program (B.2.1.20) will be used to manage loss of material of the carbon steel and gray cast iron heat exchanger components exposed to lubricating oil in the High Pressure Coolant Injection System.
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. There are no aluminum piping, piping components exposed to raw water in ESF Systems or RCIC System.
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. There are no titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water in ESF Systems or RCIC System.

Table 3.2.1, Summary of Aging Management Evaluations for the Engineered Safety Features Systems and Reactor Core Isolation Cooling System (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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. There are no titanium piping, piping components, heat exchanger components exposed to raw water in the ESF Systems or RCIC System.
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	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) and the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) will be used to manage loss of material of elastomer ducting components exposed to air - indoor uncontrolled in the Containment System, Standby Gas Treatment System, Core Spray System, High Pressure Coolant Injection System and Containment System

Table 3.2.2-1, Containment System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	V.E.E-03	3.2-1, 012	A
Closure bolting	Mechanical Closure	Nickel alloy	Air - indoor uncontrolled, air	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2-1, 014	A
Closure bolting	Mechanical Closure	Stainless steel	Air - outdoor	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2-1, 014	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2-1, 014	A
Closure bolting	Mechanical Closure	Stainless steel, Steel, Nickel alloy	Air	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2-1, 015	A
Closure bolting	Mechanical Closure	Stainless steel	Air	Cracking due to SCC	Bolting Integrity (B.2.1.10)	V.E.E-421	3.2-1, 079	A
Ducting, ducting components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.B.E-25	3.2-1, 044	A
Ducting, ducting components	Pressure Boundary	Galvanized steel	Air - indoor controlled	None	None	V.F.EP-14	3.2-1, 059	A
Ducting, ducting components	Pressure Boundary	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.F3.AP-99a	3.3-1, 094	A
Ducting, ducting components	Pressure Boundary	Stainless steel	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.F3.A-781a	3.3-1, 094a	A
Ducting, ducting components	Pressure Boundary	Aluminum	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.F3.A-451a	3.3-1, 189	C

Table 3.2.2-1, Containment System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Ducting, ducting components	Pressure Boundary	Aluminum	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.F3.A-763a	3.3-1, 234	C
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled, air - outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2-1, 040	A
Fire damper assemblies	Fire Barrier	Steel	Air	Loss of material due to general, pitting, crevice corrosion	Fire Protection (B.2.1.15)	VII.G.A-789	3.3-1, 255	A
Heat exchanger components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-29	3.2-1, 044	C
Heat exchanger components	Pressure Boundary	Aluminum	Air, condensation (internal)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	V.D2.EP-3b	3.2-1, 056	C
Heat exchanger components	Pressure Boundary	Copper alloy	Air	None	None	V.F.EP-10	3.2-1, 057	C
Heat exchanger tubes	Pressure Boundary	Aluminum	Air, condensation	Reduction of heat transfer due to fouling	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-424	3.2-1, 081	A
Piping, piping components	Pressure Boundary	Nickel alloy	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	V.C.EP-107a	3.2-1, 004	A
Piping, piping components	Pressure Boundary	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	V.C.EP-107a	3.2-1, 004	A
Piping, piping components	Pressure Boundary	Stainless steel	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.C.EP-103b	3.2-1, 007	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	V.C.EP-103b	3.2-1, 007	A

Table 3.2.2-1, Containment System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Treated water	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion (B.2.1.9)	V.C.E-09	3.2-1, 011	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.C.EP-62	3.2-1, 016	A
Piping, piping components	Pressure Boundary	Stainless steel	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.C.EP-63	3.2-1, 022	A
Piping, piping components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-29	3.2-1, 044	A
Piping, piping components	Pressure Boundary	Steel	Soil, concrete	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	Buried and Underground Piping and Tanks (B.2.1.27)	V.E.EP-111	3.2-1, 052	B
Piping, piping components	Pressure Boundary	Steel	Concrete	None	None	V.F.EP-112	3.2-1, 055	A
Piping, piping components	Pressure Boundary	Copper alloy	Air	None	None	V.F.EP-10	3.2-1, 057	A
Piping elements	Pressure Boundary	Glass	Air	None	None	V.F.EP-15	3.2-1, 060	A
Piping elements	Pressure Boundary	Glass	Treated water	None	None	V.F.EP-29	3.2-1, 060	A

Table 3.2.2-1, Containment System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components, ducting, ducting components	Pressure Boundary	Polymeric	Air	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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-477b	3.2-1, 134	A
Piping, piping components, ducting, ducting components	Pressure Boundary	Polymeric	Air, condensation	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	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-477a	3.2-1, 134	A
Piping, piping components, ducting, ducting components	Pressure Boundary	Elastomer	Air	Hardening or loss of strength due to elastomer degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3-1, 076	A
Piping, piping components, ducting, ducting components	Pressure Boundary	Elastomer	Air	Loss of material due to wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-113	3.3-1, 082	A
Piping, piping components	Pressure Boundary	Elastomer	Air	Loss of material due to wear	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.C.E-466	3.2-1, 123	***A***

Table 3.2.2-1, Containment System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Piping, piping components	Pressure Boundary	Nickel alloy	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.A4.AP-110	3.3-1, 203	A

Table 3.2.2-1 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.2.2-2, Standby Gas Treatment System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	V.E.E-03	3.2-1, 012	A
Closure bolting	Mechanical Closure	Stainless steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2-1, 014	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2-1, 014	A
Closure bolting	Mechanical Closure	Stainless Steel, Steel, Copper Alloy	Air	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2-1, 015	A
Ducting, ducting components	Pressure Boundary	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.F3.AP-99aa	3.3-1, 094	A
Ducting, ducting components	Pressure Boundary	Stainless steel	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.F3.A-781a	3.3-1, 094a	A
Ducting, ducting components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.B.E-25	3.2-1, 044	A
Insulated ducting, ducting components	Pressure Boundary	Steel	Air, condensation	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-403a	3.2-1, 069	C
Ducting, ducting components	Pressure Boundary	Aluminum	Air (external)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.E.E-444b	3.2-1, 101	C, 1
Ducting, ducting components	Pressure Boundary	Aluminum	Air (internal)	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.B.E-443b	3.2-1, 100	C, 1

Table 3.2.2-2, Standby Gas Treatment System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2-1, 040	A
Piping, piping components, tanks	Pressure Boundary	Stainless steel	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.B.EP-103b	3.2-1, 007	A
Piping, piping components	Pressure Boundary	Elastomer	Air	Hardening or loss of strength due to elastomer degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.B.E-427	3.2-1, 043	A
Piping, piping components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-29	3.2-1, 044	A
Piping, piping components	Pressure Boundary	Steel	Soil	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	Buried and Underground Piping and Tanks (B.2.1.27)	V.E.EP-111	3.2-1, 052	B
Piping, piping components	Pressure Boundary	Copper alloy	Air	None	None	V.F.EP-10	3.2-1, 057	A
Piping, piping components	Pressure Boundary	Stainless steel	Gas	None	None	V.F.EP-22	3.2-1, 063	A
Piping, piping components	Pressure Boundary	Steel	Gas	None	None	V.F.EP-7	3.2-1, 064	A
Piping, piping components	Pressure Boundary	Elastomer	Air	Loss of material due to wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-465	3.2-1, 122	A

Table 3.2.2-2, Standby Gas Treatment System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Piping, piping components, ducting, ducting components	Pressure Boundary	Polymeric	Air	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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.B.E-477b	3.2-1, 134	A
Piping, piping components, ducting, ducting components	Pressure Boundary	Polymeric	Air	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	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-477a	3.2-1, 134	A
Piping components	Pressure Boundary	Zinc	Air - indoor controlled	None	None	VII.J.A-712	3.3-1, 167	A

<u>Table 3.2.2-2 Notes</u>

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. Component type for Piping and piping components substituted for Ducting and ducting components with regard to Steel, Aluminum, Zinc, and Elastomer materials.

Table 3.2.2-3, Reactor Core Isolation Cooling System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump and valve closure bolting	Mechanical Closure	Steel	System temperature up to 288°C (550°F)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.RP-44	3.1-1, 011	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion, wear	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1-1, 063	A
Closure bolting	Mechanical Closure	Stainless steel, steel	Air - indoor uncontrolled	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2-1, 015	A
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	V.E.E-03	3.2-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2-1, 014	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2-1, 015	A
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2-1, 040	A
Heat exchanger components	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.D2.EP-60	3.2-1, 016	C
Heat exchanger components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	V.D2.EP-37	3.2-1, 034	A

Table 3.2.2-3, Reactor Core Isolation Cooling System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat exchanger tubes	Pressure Boundary	Copper alloy	Lubricating oil	Reduction of heat transfer due to fouling	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	V.D2.EP-78	3.2-1, 051	A
Heat exchanger tubes	Pressure Boundary	Stainless steel	Lubricating oil	Reduction of heat transfer due to fouling	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	V.D2.EP-79	3.2-1, 051	A
Heat exchanger tubes	Pressure Boundary	Copper alloy	Air	Reduction of heat transfer due to fouling	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-424	3.2-1, 081	A
Heat exchanger tubes	Pressure Boundary	Copper alloy	Treated water	Reduction of heat transfer due to fouling	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.E.SP-100	3.4-1, 018	A
Insulated piping, piping components	Pressure Boundary	Steel	Air, condensation	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-403a	3.2-1, 069	A
Reactor coolant pressure boundary components: piping, piping components; other pressure retaining components with fatigue analyses	Pressure Boundary	Stainless steel	Reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A
Reactor coolant pressure boundary components: piping, piping components; other pressure retaining components with fatigue analyses	Pressure Boundary	Steel (with or without nickel alloy or stainless steel cladding)	Reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A

Table 3.2.2-3, Reactor Core Isolation Cooling System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Class 1 piping, fittings and branch connections < NPS 4	Pressure Boundary	Stainless steel Steel (with or without nickel alloy or stainless steel cladding)	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), thermal, mechanical, vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1), Water Chemistry (B.2.1.2) and ASME Code Class 1 Small-bore Piping (B.2.1.22)	IV.C1.RP-230	3.1-1, 039	A
Piping, piping components	Pressure Boundary	Aluminum	Air, condensation (external)	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	V.E.EP-114b	3.2-1, 042	A
Piping, piping components	Pressure Boundary	Steel	Reactor coolant	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-23	3.1-1, 060	A
Reactor coolant pressure boundary components	Pressure Boundary	Stainless steel	Reactor coolant	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	A
Piping, piping components greater than or equal to 4 NPS	Pressure Boundary	Stainless steel	Reactor coolant	Cracking due to SCC, IGSCC	BWR Stress Corrosion Cracking (B.2.1.5) and Water Chemistry (B.2.1.2)	IV.C1.R-20	3.1-1, 097	B

Table 3.2.2-3, Reactor Core Isolation Cooling System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor coolant system components: Components defined as ASME Section XI components (e.g., reactor coolant pressure boundary components, core support structure components, ASME Class 2 or 3 components, including associated pressure-retaining welds) not managed by other AMR line items in GALL-SLR Chapter IV	Pressure Boundary	Steel	Air - indoor uncontrolled	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) and Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
Piping, piping components	Pressure Boundary	Steel	Air - indoor uncontrolled, air - outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Piping, piping components - RCPB	Pressure Boundary	Steel	Treated water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1-1, 133	A
Piping, piping components	Pressure Boundary	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Cumulative fatigue damage due to fatigue	Section 4.3 “Metal Fatigue”	V.D2.E-10	3.2-1, 001	A
Piping, piping components	Pressure Boundary	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2-1, 004	A
Piping, piping components	Pressure Boundary	Stainless steel	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A

Table 3.2.2-3, Reactor Core Isolation Cooling System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Piping, piping components	Pressure Boundary	Steel	Treated water	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-09	3.2-1, 011	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.D2.EP-60	3.2-1, 016	A
Piping, piping components	Pressure Boundary	Aluminum	Treated water	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.D2.EP-71	3.2-1, 017	A
Piping, piping components	Pressure Boundary	Stainless steel	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.D2.EP-73	3.2-1, 022	A
Piping, piping components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	V.D2.EP-27	3.2-1, 034	A
Piping, piping components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-29	3.2-1, 044	A
Piping, piping components	Pressure Boundary	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	V.D2.EP-61b	3.2-1, 048	A
Piping, piping components	Pressure Boundary	Steel	Lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	V.D2.EP-77	3.2-1, 049	A
Piping, piping components	Pressure Boundary	Copper alloy	Lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	V.D2.EP-76	3.2-1, 050	A
Piping, piping components	Pressure Boundary	Copper alloy	Air	None	None	V.F.EP-10	3.2-1, 057	A

Table 3.2.2-3, Reactor Core Isolation Cooling System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Piping elements	Pressure Boundary	Glass	Air	None	None	V.F.EP-15	3.2-1, 060	A
Piping elements	Pressure Boundary	Glass	Lubricating oil	None	None	V.F.EP-16	3.2-1, 060	A
Piping, piping components	Pressure Boundary	Stainless steel	Gas	None	None	V.F.EP-22	3.2-1, 063	A
Piping, Piping components	Pressure Boundary	Copper Alloy	Treated water	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-408	3.2-1, 065	A
Piping, Piping components	Pressure Boundary	Steel	Treated water	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-408	3.2-1, 065	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2-1, 090	A
Piping, piping components	Pressure Boundary	Stainless steel	Treated water >60°C (>140°F)	Cracking due to SCC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.C.E-457	3.2-1, 114	A
Piping, piping components	Pressure Boundary	Stainless steel	Treated water >60°C (>140°F)	Cracking due to SCC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.D2.E-457	3.2-1, 114	A
Piping, piping components	Pressure Boundary	Copper alloy	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.A4.AP-140	3.3-1, 022	A
Piping, piping components	Pressure Boundary	Gray cast iron	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.E3.AP-31	3.3-1, 072	A
Piping, piping components	Pressure Boundary	Stainless steel	Lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.E4.AP-138	3.3-1, 100	A

Table 3.2.2-3, Reactor Core Isolation Cooling System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Piping, piping components	Pressure Boundary	Copper alloy	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.A.SP-101	3.4-1, 016	A
Piping, piping components	Pressure Boundary	Gray cast iron	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VIII.E.SP-27	3.4-1, 033	A
Tanks	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.D2.EP-60	3.2-1, 016	A
Tanks	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-29	3.2-1, 044	C
Tanks	Pressure Boundary	Steel	Treated waterr	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2-1, 090	C
Tanks	Pressure Boundary	Gray cast iron	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.E3.AP-31	3.3-1, 072	A

Table 3.2.2-3 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.2.2-4, High Pressure Coolant Injection System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Pump and valve closure bolting	Mechanical Closure	Steel	System temperature up to 288°C (550°F)	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.RP-44	3.1-1, 011	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled (external)	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1-1, 067	A
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	V.E.E-03	3.2-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2-1, 014	A
Closure bolting	Mechanical Closure	Steel	Any	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2-1, 015	A
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2-1, 040	A
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2-1, 040	A
Heat exchanger components	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.D2.EP-60	3.2-1, 016	C
Heat exchanger components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	V.D2.EP-37	3.2-1, 034	A

Table 3.2.2-4, High Pressure Coolant Injection System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat exchanger components (HPCI Gland Seal Condenser)	Pressure Boundary	Steel	Condensation	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-27	3.2-1, 046	C
Heat exchanger tubes	Pressure Boundary	Copper alloy	Lubricating oil	Reduction of heat transfer due to fouling	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	V.D2.EP-78	3.2-1, 051	A
Heat exchanger components (HPCI Gland Seal Condenser)	Pressure Boundary	Copper Alloy	Air, condensation	None	None	V.F.EP-10	3.2-1, 057	C
Heat exchanger components	Pressure Boundary	Steel	Lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	V.D2.E-473	3.2-1, 130	A
Heat exchanger components (HPCI Gland Seal Condenser)	Pressure Boundary	Copper alloy	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-140	3.3-1, 022	C
Heat exchanger tubes	Pressure Boundary	Copper alloy	Treated water	Reduction of heat transfer due to fouling	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.E.SP-100	3.4-1, 018	A
Insulated piping, piping components	Pressure Boundary	Steel	Air, condensation	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-403a	3.2-1, 069	A
Reactor coolant pressure boundary components: piping, piping components; other pressure retaining components with fatigue analyses	Pressure Boundary	Stainless steel	Reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A

Table 3.2.2-4, High Pressure Coolant Injection System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor coolant pressure boundary components: piping, piping components; other pressure retaining components with fatigue analyses	Pressure Boundary, Throttle	Steel (with or without nickel alloy or stainless steel cladding)	Reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A
Class 1 piping, fittings and branch connections < NPS 4	Throttle, Pressure Boundary	Stainless steel	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), thermal, mechanical, vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1), Water Chemistry (B.2.1.2) and ASME Code Class 1 Small-bore Piping (B.2.1.22)	IV.C1.RP-230	3.1-1, 039	A
Class 1 piping, fittings and branch connections < NPS 4	Pressure Boundary	Steel (with or without nickel alloy or stainless steel cladding)	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), thermal, mechanical, vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1), Water Chemistry (B.2.1.2) and ASME Code Class 1 Small-bore Piping (B.2.1.22)	IV.C1.RP-230	3.1-1, 039	A
Piping, piping components	Pressure Boundary	Steel	Reactor coolant	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-23	3.1-1, 060	A
Reactor coolant pressure boundary components	Pressure Boundary	stainless steel	Reactor coolant	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	A

Table 3.2.2-4, High Pressure Coolant Injection System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Reactor Coolant	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-406	3.1-1, 110	A
Reactor coolant system components: Components defined as ASME Section XI components (e.g., reactor coolant pressure boundary components, core support structure components, ASME Class 2 or 3 components, including associated pressure-retaining welds) not managed by other AMR line items in GALL-SLR Chapter IV	Throttle, Pressure Boundary	Stainless steel	Treated water	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) and Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
Reactor coolant system components: Components defined as ASME Section XI components (e.g., reactor coolant pressure boundary components, core support structure components, ASME Class 2 or 3 components, including associated pressure-retaining welds) not managed by other AMR line items in GALL-SLR Chapter IV	Flow Restriction, Pressure Boundary	Steel	Air, Treated water	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) and Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A

Table 3.2.2-4, High Pressure Coolant Injection System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Piping, piping components - RCPB	Pressure Boundary	Steel	Treated water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1-1, 133	A
Piping, piping components	Throttle, Pressure Boundary	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Cumulative fatigue damage due to fatigue	Section 4.3 “Metal Fatigue	V.D2.E-10	3.2-1, 001	A
Piping, piping components	Pressure Boundary	Nickel alloy	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2-1, 004	A
Piping, piping components	Pressure Boundary	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2-1, 004	A
Piping, piping components, tanks	Pressure Boundary	Stainless steel	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A
Piping, piping components	Pressure Boundary	Steel	Steam	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-07	3.2-1, 011	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-09	3.2-1, 011	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.D2.EP-60	3.2-1, 016	A
Piping, piping components, heat exchanger components	Pressure Boundary	Nickel alloy	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.D2.E-428	3.2-1, 022	A

Table 3.2.2-4, High Pressure Coolant Injection System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Piping, piping components, heat exchanger components	Pressure Boundary	Stainless steel	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.D2.EP-73	3.2-1, 022	A
Piping, piping components	Pressure Boundary	Stainless steel	Closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	V.D2.EP-95	3.2-1, 031	A
Piping, piping components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	V.D2.EP-27	3.2-1, 034	A
Piping, piping components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-29	3.2-1, 044	A
Piping, piping components, tanks	Pressure Boundary	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	V.D2.EP-61b	3.2-1, 048	A
Piping, piping components	Pressure Boundary	Steel	Lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	V.D2.EP-77	3.2-1, 049	A
Piping, piping components	Throttle, Pressure Boundary	Stainless steel	Lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VIII.A.SP-95	3.4-1, 044	A
Piping, piping components	Pressure Boundary	Copper alloy	Lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	V.D2.EP-76	3.4-1, 044	A
Piping elements	Pressure Boundary	Glass	Air	None	None	V.F.EP-15	3.2-1, 060	A
Piping elements	Pressure Boundary	Glass	Lubricating oil	None	None	V.F.EP-16	3.2-1, 060	A

Table 3.2.2-4, High Pressure Coolant Injection System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, Piping components	Pressure Boundary	Steel	Treated water	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-408	3.2-1, 065	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2-1, 090	A
Piping, piping components	Pressure Boundary	Stainless steel	Treated water >60°C (>140°F)	Cracking due to SCC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.D2.E-457	3.2-1, 114	A
Piping, piping components, ducting, ducting components	Pressure Boundary	Polymeric	Air, condensation,	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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-477b	3.2-1, 134	A
Piping, piping components, ducting, ducting components	Pressure Boundary	Polymeric	Air, condensation,	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	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-477a	3.2-1, 134	A
Piping, piping components	Pressure Boundary	Gray cast iron	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.E3.AP-31	3.3-1, 072	A

Table 3.2.2-4, High Pressure Coolant Injection System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless steel	Lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.E4.AP-138	3.3-1, 100	A
Tanks	Pressure Boundary	Steel	Lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	V.D2.EP-77	3.2-1, 049	C

Table 3.2.2-4 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.2.2-5, Residual Heat Removal System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	V.E.E-03	3.2-1, 012	A
Closure bolting	Mechanical Closure, Structural Support	Stainless steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2-1, 014	A
Closure bolting	Mechanical Closure, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2-1, 014	A
Closure bolting	Mechanical Closure, Structural Support	Steel	Any	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2-1, 015	A
Closure bolting	Mechanical Closure, Structural Support	Stainless steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC (steel, copper alloy in raw water, waste water only)	Bolting Integrity (B.2.1.10)	V.E.E-418	3.2-1, 076	A
Closure bolting	Mechanical Closure, Structural Support	Stainless steel	Air	Cracking due to SCC	Bolting Integrity (B.2.1.10)	V.E.E-421	3.2-1, 079	A
External surfaces	Heat Transfer, Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2-1, 040	A
Heat exchanger tubes	Pressure Boundary	Stainless steel	Treated water	Reduction of heat transfer due to fouling	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.D2.EP-74	3.2-1, 019	A

Table 3.2.2-5, Residual Heat Removal System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat exchanger components	Heat Transfer, Pressure Boundary	Stainless steel	Treated water >60°C (>140°F)	Cracking due to SCC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-112	3.3-1, 020	A
Reactor coolant pressure boundary components: piping, piping components; other pressure retaining components with fatigue analyses	Pressure Boundary	Cast austenitic stainless steel	Reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A
Reactor coolant pressure boundary components: piping, piping components; other pressure retaining components with fatigue analyses	Pressure Boundary	Stainless steel	Reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A
Reactor coolant pressure boundary components: piping, piping components; other pressure retaining components with fatigue analyses	Pressure Boundary	Steel (with or without nickel alloy or stainless steel cladding)	Reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A
Class 1 piping, fittings and branch connections < NPS 4	Pressure Boundary	Stainless steel	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), thermal, mechanical, vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1), Water Chemistry (B.2.1.2) and ASME Code Class 1 Small-bore Piping (B.2.1.22)	IV.C1.RP-230	3.1-1, 039	A

Table 3.2.2-5, Residual Heat Removal System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor coolant pressure boundary components	Pressure Boundary	Stainless steel	Reactor coolant	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	A
Reactor coolant pressure boundary components	Pressure Boundary	Cast austenitic stainless steel	Reactor coolant	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.C1.RP-158	3.1-1, 079	A
Piping, piping components greater than or equal to 4 NPS	Pressure Boundary	Stainless steel	Reactor coolant	Cracking due to SCC, IGSCC	BWR Stress Corrosion Cracking (B.2.1.5) and Water Chemistry (B.2.1.2)	IV.C1.R-20	3.1-1, 097	B
Reactor coolant system components: Components defined as ASME Section XI components (e.g., reactor coolant pressure boundary components, core support structure components, ASME Class 2 or 3 components, including associated pressure-retaining welds) not managed by other AMR line items in GALL-SLR Chapter IV	Pressure Boundary	Cast austenitic stainless steel	Reactor coolant	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) and Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A

Table 3.2.2-5, Residual Heat Removal System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Reactor coolant system components: Components defined as ASME Section XI components (e.g., reactor coolant pressure boundary components, core support structure components, ASME Class 2 or 3 components, including associated pressure-retaining welds) not managed by other AMR line items in GALL-SLR Chapter IV	Pressure Boundary	Steel	Air	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) and Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
Piping, piping components	Pressure Boundary	Steel	Air - indoor uncontrolled, air - outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Insulated piping, piping components	Pressure Boundary	Steel	Air, condensation	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-403a	3.2-1, 069	A
Piping, piping components - RCPB	Pressure Boundary	Steel	Treated water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1-1, 133	A
Piping, piping components	Pressure Boundary	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Cumulative fatigue damage due to fatigue	Section 4.3 “Metal Fatigue”	V.D2.E-10	3.2-1, 001	A
Piping, piping components	Pressure Boundary	Cast austenitic stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2-1, 004	A

Table 3.2.2-5, Residual Heat Removal System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2-1, 004	A
Drywell and suppression chamber spray system (internal surfaces): flow orifice; spray nozzles	Pressure Boundary	Metallic	Air - indoor uncontrolled, condensation	Loss of material due to general, pitting, crevice corrosion; flow blockage due to fouling	One-Time Inspection (B.2.1.20)	V.D2.EP-113a	3.2-1, 006	A
Piping, piping components, tanks	Pressure Boundary	Cast austenitic stainless steel	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A
Piping, piping components	Pressure Boundary	Stainless steel	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-09	3.2-1, 011	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.D2.EP-60	3.2-1, 016	A
Piping, piping components	Pressure Boundary	Aluminum	Treated water	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.D2.EP-71	3.2-1, 017	A
Piping, piping components, heat exchanger components	Pressure Boundary	Stainless steel	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.D2.EP-73	3.2-1, 022	A
Piping, piping components	Pressure Boundary	Stainless steel	Closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	Closed Treated Water Systems (B.2.1.12)	V.D2.EP-98	3.2-1, 028	A
Piping, piping components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	V.D2.EP-27	3.2-1, 034	A

Table 3.2.2-5, Residual Heat Removal System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-29	3.2-1, 044	A
Piping, piping components, tanks	Pressure Boundary	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	V.D2.EP-61b	3.2-1, 048	A
Piping, piping components	Pressure Boundary	Steel	Lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	V.D2.EP-77	3.2-1, 049	A
Piping, piping components	Pressure Boundary	Copper alloy	Air	None	None	V.F.EP-10	3.2-1, 057	A
Piping, Piping components	Pressure Boundary	Steel	Treated water	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-408	3.2-1, 065	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2-1, 090	A
Piping, piping components, tanks	Pressure Boundary	Aluminum	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.E.E-444b	3.2-1, 101	A
Piping, piping components	Pressure Boundary	Stainless steel	Treated water >60°C (>140°F)	Cracking due to SCC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.D2.E-457	3.2-1, 114	A
Piping, piping components	Pressure Boundary	Copper alloy	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.A4.AP-140	3.3-1, 022	A
Piping, piping components	Pressure Boundary	Gray cast iron	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.A4.AP-31	3.3-1, 072	A
Piping, piping components	Pressure Boundary, Filter	Gray cast iron	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.E4.AP-31	3.3-1, 072	A

Table 3.2.2-5 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.2.2-6, Core Spray System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	V.E.E-03	3.2-1, 012	A
Closure bolting	Mechanical Closure, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2-1, 014	A
Closure bolting	Mechanical Closure, Structural Support	Steel	Air	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2-1, 015	A
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2-1, 040	A
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2-1, 040	A
Reactor coolant pressure boundary components: piping, piping components; other pressure retaining components with fatigue analyses	Pressure Boundary	Cast austenitic stainless steel	Reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A
Reactor coolant pressure boundary components: piping, piping components; other pressure retaining components with fatigue analyses	Pressure Boundary	Stainless steel	Reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A

Table 3.2.2-6, Core Spray System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor coolant pressure boundary components: piping, piping components; other pressure retaining components with fatigue analyses	Pressure Boundary	Steel (with or without nickel alloy or stainless steel cladding)	Reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A
Class 1 piping, fittings and branch connections < NPS 4	Pressure Boundary	Stainless steel	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), thermal, mechanical, vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1), Water Chemistry (B.2.1.2) and ASME Code Class 1 Small-bore Piping (B.2.1.22)	IV.C1.RP-230	3.1-1, 039	A
Class 1 piping, fittings and branch connections < NPS 4	Pressure Boundary	Steel (with or without nickel alloy or stainless steel cladding)	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), thermal, mechanical, vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1), Water Chemistry (B.2.1.2) and ASME Code Class 1 Small-bore Piping (B.2.1.22)	IV.C1.RP-230	3.1-1, 039	A
Reactor coolant pressure boundary components	Pressure Boundary	Stainless steel	Reactor coolant	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	A
Reactor coolant pressure boundary components	Pressure Boundary	Steel (with stainless steel or nickel alloy cladding)	Reactor coolant	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	A

Table 3.2.2-6, Core Spray System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor coolant pressure boundary components	Pressure Boundary	Cast austenitic stainless steel	Reactor coolant	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.C1.RP-158	3.1-1, 079	A
Piping, piping components greater than or equal to 4 NPS	Pressure Boundary	Stainless steel	Reactor coolant	Cracking due to SCC, IGSCC	BWR Stress Corrosion Cracking (B.2.1.5) and Water Chemistry (B.2.1.2)	IV.C1.R-20	3.1-1, 097	B
Reactor coolant system components: Components defined as ASME Section XI components (e.g., reactor coolant pressure boundary components, core support structure components, ASME Class 2 or 3 components, including associated pressure-retaining welds) not managed by other AMR line items in GALL-SLR Chapter IV	Pressure Boundary	Cast austenitic stainless steel	Reactor Coolant	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) and Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A

Table 3.2.2-6, Core Spray System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor coolant system components: Components defined as ASME Section XI components (e.g., reactor coolant pressure boundary components, core support structure components, ASME Class 2 or 3 components, including associated pressure-retaining welds) not managed by other AMR line items in GALL-SLR Chapter IV	Pressure Boundary	Steel	Air	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) and Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
Piping, piping components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Piping, piping components	Pressure Boundary	Stainless steel	Closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	Closed Treated Water Systems (B.2.1.12)	V.D2.EP-98	3.2-1, 028	A
Piping, piping components - RCPB	Pressure Boundary	Steel	Treated water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1-1, 133	A
Piping, piping components	Pressure Boundary	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Cumulative fatigue damage due to fatigue	Section 4.3 “Metal Fatigue”	V.D2.E-10	3.2-1, 001	A
Piping, piping components	Pressure Boundary	Cast austenitic stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2-1, 004	A

Table 3.2.2-6, Core Spray System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	V.D2.EP-107a	3.2-1, 004	A
Piping, piping components, tanks	Pressure Boundary	Cast austenitic stainless steel	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A
Piping, piping components	Pressure Boundary	Stainless steel	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.D2.EP-103b	3.2-1, 007	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion (B.2.1.9)	V.D2.E-09	3.2-1, 011	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.D2.EP-60	3.2-1, 016	A
Piping, piping components	Pressure Boundary	Aluminum	Treated water	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.D2.EP-71	3.2-1, 017	A
Piping, piping components, heat exchanger components	Pressure Boundary	Stainless steel	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	V.D2.EP-73	3.2-1, 022	A
Piping, piping components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-29	3.2-1, 044	A
Piping, piping components	Pressure Boundary	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	V.D2.EP-61b	3.2-1, 048	A
Piping, piping components	Pressure Boundary	Steel	Lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	V.D2.E-77	3.2-1, 049	A
Piping, piping components	Pressure Boundary	Stainless steel	Gas	None	None	V.F.EP-22	3.2-1, 063	A

Table 3.2.2-6, Core Spray System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Piping, piping components, tanks	Pressure Boundary	Steel	Treated water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	V.D2.E-434	3.2-1, 090	A
Piping, piping components, ducting, ducting components	Pressure Boundary	Polymeric	Air	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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-477b	3.2-1, 134	A
Piping, piping components, ducting, ducting components	Pressure Boundary	Polymeric	Air	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	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-477a	3.2-1, 134	A
Piping, piping components	Pressure Boundary	Gray cast iron	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.E4.AP-31	3.3-1, 072	A
Tanks	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-29	3.2-1, 044	C

Table 3.2.2-6 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.2.2-7, Containment Atmosphere Dilution System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	V.E.E-03	3.2-1, 012	A, 3
Closure bolting	Mechanical Closure, Structural Support	Stainless steel	Air - indoor uncontrolled, air - outdoor	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2-1, 014	A
Closure bolting	Mechanical Closure, Structural Support	Steel	Air - indoor uncontrolled, air - outdoor	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	V.E.E-02	3.2-1, 014	A
Closure bolting	Mechanical Closure, Structural Support	Steel	Air	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	V.E.EP-116	3.2-1, 015	A
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled, air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2-1, 040	A
Heat exchanger components	Pressure Boundary	Stainless steel	Gas	None	None	V.F.EP-22	3.2-1, 063	C
Heat exchanger components	Pressure Boundary	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.F3.A-770a	3.3-1, 241	A, 2
Piping, piping components	Pressure Boundary	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	V.C.EP-107a	3.2-1, 004	A, 2
Piping, piping components	Pressure Boundary	Stainless steel	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.C.EP-103b	3.2-1, 007	A, 2
Piping, piping components	Pressure Boundary	Aluminum	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	V.E.EP-114b	3.2-1, 042	A, 2

Table 3.2.2-7, Containment Atmosphere Dilution System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Piping, piping components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	V.D2.E-29	3.2-1, 044	A
Piping, piping components	Pressure Boundary	Stainless steel	Soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	Buried and Underground Piping and Tanks (B.2.1.27)	V.E.EP-72	3.2-1, 053	B
Piping, piping components	Pressure Boundary	Copper alloy	Air	None	None	V.F.EP-10	3.2-1, 057	A
Piping, piping components	Pressure Boundary	Stainless steel	Gas	None	None	V.F.EP-22	3.2-1, 063	A
Piping, piping components	Pressure Boundary	Steel	Gas	None	None	V.F.EP-7	3.2-1, 064	A
Piping, piping components	Pressure Boundary	Aluminum	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	V.E.E-444b	3.2-1, 101	A, 2
Piping, piping components	Pressure Boundary	Aluminum	Gas	None	None	VII.J.AP-37	3.3-1, 113	A
Tanks	Pressure Boundary	Stainless Steel	Gas	None	None	V.F.EP-22	3.2-1, 063	A
Tanks	Pressure Boundary	Steel	Gas	None	None	V.F.EP-7	3.2-1, 064	C

<u>Table 3.2.2-7 Notes</u>

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

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.

- Emergency High Pressure Makeup System (2.3.3.1)
- Auxiliary Boiler System (2.3.3.2)
- Fuel Oil System (2.3.3.3)
- Residual Heat Removal Service Water System (2.3.3.4)
- Raw Cooling Water System (2.3.3.5)
- Raw Service Water System (2.3.3.6)
- High Pressure Fire Protection (Diesel Driven Pump) System (2.3.3.7)
- Potable Water System (2.3.3.8)
- Normal Ventilation System, includes Turbine Building Ventilation System, Radwaste Ventilation System, and Diesel Generator Room Ventilation System (2.3.3.9)
- Air Conditioning System (2.3.3.10)
- Control Air System (2.3.3.11)
- Service Air System (2.3.3.12)
- CO_2 Storage, Fire Protection/Purge System (2.3.3.13)
- Station Drainage System (2.3.3.14)
- Sampling and Water Quality System (2.3.3.15)
- Building Heating System (2.3.3.16)
- Hypochlorite System (2.3.3.17)
- Demineralizer Backwash Air System (2.3.3.18)
- Standby Liquid Control System (2.3.3.19)
- Off-Gas System (2.3.3.20)
- Emergency Equipment Cooling Water System (2.3.3.21)
- Reactor Water Cleanup System (2.3.3.22)
- Reactor Building Closed Cooling Water System (2.3.3.23)
- Auxiliary Decay Heat Removal System (2.3.3.24)
- Containment Inerting System (2.3.3.25)
- Radwaste System (2.3.3.26)
- Spent Fuel Pool Cooling/Cleanup System (2.3.3.27)
- Fuel Handling and Storage System (2.3.3.28)
- Standby Diesel Generators (2.3.3.29)
- Supplemental Diesel Generator System (2.3.3.30)
- Control Rod Drive System (2.3.3.31)
- Diesel Generator Starting Air System (2.3.3.32)
- Cranes and Hoists (2.3.3.33)
- Sewage System (2.3.3.34)

- Diverse and Flexible Coping Strategies (FLEX) System (2.3.3.35)
- Security System (2.3.3.36)
- Radiation Monitoring System (2.3.3.37)
- Hardened Containment Venting System (2.3.3.38)

3.3.2 Results

The following tables summarize the results of the aging management review for Auxiliary Systems.

- Table 3.3.2-1, Emergency High Pressure Makeup System - Summary of Aging Management Evaluation
- Table 3.3.2-2, Auxiliary Boiler System - Summary of Aging Management Evaluation
- Table 3.3.2-3, Fuel Oil System - Summary of Aging Management Evaluation
- Table 3.3.2-4, Residual Heat Removal Service Water System - Summary of Aging Management Evaluation
- Table 3.3.2-5, Raw Cooling Water System - Summary of Aging Management Evaluation
- Table 3.3.2-6, Raw Service Water System - Summary of Aging Management Evaluation
- Table 3.3.2-7, High Pressure Fire Protection (Diesel Driven Pump) System - Summary of Aging Management Evaluation
- Table 3.3.2-8, Potable Water System - Summary of Aging Management Evaluation
- Table 3.3.2-9, Normal Ventilation System - Summary of Aging Management Evaluation
- Table 3.3.2-10, Air Conditioning System - Summary of Aging Management Evaluation
- Table 3.3.2-11, Control Air System - Summary of Aging Management Evaluation
- Table 3.3.2-12, Service Air System - Summary of Aging Management Evaluation
- Table 3.3.2-13, CO_2 Storage, Fire Protection/Purge System - Summary of Aging Management Evaluation
- Table 3.3.2-14, Station Drainage System - Summary of Aging Management Evaluation
- Table 3.3.2-15, Sampling and Water Quality System - Summary of 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 Emergency High Pressure Makeup System

Materials

The materials of construction for the Emergency High Pressure Makeup System components are:

-
- High-strength steel
- Galvanized steel
- Metallic
- Stainless steel
- Steel

Environments

The Emergency High Pressure Makeup System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air - outdoor
- Air, condensation

- Lubricating Oil
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the Emergency High Pressure Makeup System components 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 Emergency High Pressure Makeup System components:

- Water Chemistry (B.2.1.2)
- Flow-Accelerated Corrosion (B.2.1.9)
- Bolting Integrity (B.2.1.10)
- One-Time Inspection (B.2.1.20)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Lubricating Oil Analysis (B.2.1.25)
- TLAA (Section 4.3)

3.3.2.1.2 Auxiliary Boiler System

Materials

The materials of construction for the Auxiliary Boiler System components are:

- Copper alloy
- Copper alloy (>15% Zn or >8% Al)
- High-strength steel
- Stainless steel
- Steel

Environments

The Auxiliary Boiler System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air, condensation
- Steam
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the Auxiliary Boiler System components require management:

- Cracking due to SCC
- Cumulative fatigue damage
- Long-term loss of material
- Loss of material
- Loss of preload due to thermal effects, gasket creep, self-loosening
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Auxiliary Boiler System components:

- Water Chemistry (B.2.1.2)
- Flow-Accelerated Corrosion (B.2.1.9)
- Bolting Integrity (B.2.1.10)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- TLAA (Section 4.3)

3.3.2.1.3 Fuel Oil System

Materials

The materials of construction for the Fuel Oil System components are:

- Aluminum
- Copper alloy
- Elastomer
- High-strength steel
- Stainless steel
- Steel

Environments

The Fuel Oil System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air - outdoor
- Air, condensate
- Concrete
- Fuel oil

Aging Effects Requiring Management

The following aging effects associated with the Fuel Oil System components 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 Oil System components:

- Bolting Integrity (B.2.1.10)
- Fuel Oil Chemistry (B.2.1.18)
- One-Time Inspection (B.2.1.20)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)

3.3.2.1.4 Residual Heat Removal Service Water System

Materials

The materials of construction for the Residual Heat Removal Service Water System components are:

- Aluminum
- Copper alloy
- Gray cast iron, ductile iron
- High-strength steel
- Polymeric
- Stainless steel
- Steel
- Steel with internal coatings/linings

Environments

The Residual Heat Removal Service Water System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air - outdoor
- Air, condensate
- Concrete
- Lubricating oil
- Raw water

- Soil
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the Residual Heat Removal Service Water System components 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 due to fouling
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Residual Heat Removal Service Water System components:

- Water Chemistry (B.2.1.2)
- Bolting Integrity (B.2.1.10)
- Open-Cycle Cooling Water System (B.2.1.11)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Lubricating Oil Analysis (B.2.1.25)
- Buried and Underground Piping and Tanks (B.2.1.27)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)
- TLAA (Section 4.3)

3.3.2.1.5 Raw Cooling Water System

Materials

The materials of construction for the Raw Cooling Water System components are:

- Copper alloy
- Copper alloy (>15% Zn or >8% Al)
- Elastomer
- Gray cast iron, ductile iron
- High-strength steel
- Polymeric

- Stainless steel
- Steel

Environments

The Raw Cooling Water System components are exposed to the following environments:
- Air
- Air - indoor uncontrolled
- Air - outdoor
- Air, condensation
- Lubricating oil
- Raw water
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the Raw Cooling Water System components require management:
- Cracking
- 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 Raw Cooling Water System components:
- Water Chemistry (B.2.1.2)
- Flow-Accelerated Corrosion (B.2.1.9)
- Bolting Integrity (B.2.1.10)
- Open-Cycle Cooling Water System (B.2.1.11)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Lubricating Oil Analysis (B.2.1.25)

3.3.2.1.6 Raw Service Water System

Materials

The materials of construction for the Raw Service Water System components are:
- Copper Alloy
- Copper alloy (>15% Zn or >8% Al)

- Gray cast iron, ductile iron
- High-strength steel
- Stainless steel
- Steel

Environments

The Raw Service Water System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air - outdoor
- Air, condensation
- Raw water
- Soil

Aging Effects Requiring Management

The following aging effects associated with the Raw Service Water System components require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the Raw Service Water System components:

- Bolting Integrity (B.2.1.10)
- Open-Cycle Cooling Water System (B.2.1.11)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Buried and Underground Piping and Tanks (B.2.1.27)

3.3.2.1.7 High Pressure Fire Protection (Diesel Driven Pump) System

Materials

The materials of construction for the High Pressure Fire Protection (Diesel Driven Pump) System components are:

- Aluminum
- Copper alloy
- Copper alloy (>15% Zn or >8% Al)
- Elastomer
- Glass
- Gray cast iron

- Gray cast iron, ductile iron
- High-strength steel
- Metallic
- Stainless steel
- Steel

Environments

The High Pressure Fire Protection (Diesel Driven Pump) System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air - outdoor
- Air - condensate
- Any
- Closed-cycle cooling water
- Concrete
- Fuel Oil
- Gas
- Lubricating oil
- Raw water
- Soil
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the High Pressure Fire Protection (Diesel Driven Pump) System components require management:

- Cracking
- Cumulative fatigue damage
- Flow blockage due to fouling
- 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

Aging Management Programs

The following aging management programs manage the aging effects for the High Pressure Fire Protection (Diesel Driven Pump) System components:

- Bolting Integrity (B.2.1.10)
- Open-Cycle Cooling Water System (B.2.1.11)

- Closed Treated Water Systems (B.2.1.12)
- Fire Protection (B.2.1.15)
- Fire Water System (B.2.1.16)
- Fuel Oil Chemistry (B.2.1.18)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Lubricating Oil Analysis (B.2.1.25)
- Buried and Underground Piping and Tanks (B.2.1.27)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.27)
- TLAA (Section 4.3)

3.3.2.1.8 Potable Water System

Materials

The materials of construction for the Potable Water System components are:

- Copper alloy
- Copper alloy (>15% Zn or >8% Al)
- High-strength steel
- Stainless steel
- Steel

Environments

The Potable Water System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air - outdoor
- Air, Condensation
- Raw water (potable)

Aging Effects Requiring Management

The following aging effects associated with the Potable Water System components require management:

- Cracking
- 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 Potable Water System components:

- Bolting Integrity (B.2.1.10)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)

3.3.2.1.9 Normal Ventilation System

Materials

The materials of construction for the Normal Ventilation System components are:

- Elastomer
- High-strength steel
- Metallic
- Stainless steel
- Steel

Environments

The Normal Ventilation System components are exposed to the following environments:

- Air
- Air - outdoor
- Air - indoor uncontrolled
- Air, condensation
- Condensation

Aging Effects Requiring Management

The following aging effects associated with the Normal Ventilation System components 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 Normal Ventilation System components:

- Bolting Integrity (B.2.1.10)
- Fire Protection (B.2.1.15)
- One-Time Inspection (B.2.1.20)

- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)

3.3.2.1.10 Air Conditioning System

Materials

The materials of construction for the Air Conditioning System components are:

- Aluminum
- Copper alloy
- Copper alloy (>15% Zn or >8% Al)
- Elastomer
- Glass
- Gray cast iron, ductile iron
- High-strength steel
- Polymeric
- Stainless steel
- Steel

Environments

The Air Conditioning System components are exposed to the following environments:

- Air
- Air, condensation
- Air - indoor controlled
- Air - indoor uncontrolled
- Air - outdoor
- Closed-cycle cooling water
- Condensation
- Gas
- Lubricating oil
- Raw water (potable)

Aging Effects Requiring Management

The following aging effects associated with the Air Conditioning System components require management:

- Cracking
- Hardening or loss of strength
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following aging management programs manage the aging effects for the Air Conditioning System components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- Fire Protection (B.2.1.15)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Lubricating Oil Analysis (B.2.1.25)

3.3.2.1.11 Control Air System

Materials

The materials of construction for the Control Air System components are:

- Aluminum
- Copper alloy
- High-strength steel
- Metallic
- Nickel Alloy
- Stainless steel
- Steel
- Steel with internal coatings/linings

Environments

The Control Air System components are exposed to the following environments:

- Air
- Air-Dry
- Air - indoor uncontrolled
- Air, Condensation
- Condensation

Aging Effects Requiring Management

The following aging effects associated with the Control Air System components require management:

- Cracking
- 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 Control Air System components:

- Bolting Integrity (B.2.1.10)
- Compressed Air Monitoring (B.2.1.14)
- One-Time Inspection (B.2.1.20)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)

3.3.2.1.12 Service Air System

Materials

The materials of construction for the Service Air System components are:

- Copper alloy
- High-strength steel
- Stainless steel
- Steel
- Steel with internal coatings/linings

Environments

The Service Air System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air-dry
- Air, condensation
- Condensation

Aging Effects Requiring Management

The following aging effects associated with the Service Air System components require management:

- Cracking
- 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 Service Air System components:

- Bolting Integrity (B.2.1.10)

- One-Time Inspection (B.2.1.20)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)

3.3.2.1.13 CO_2 Storage, Fire Protection/Purge System

Materials

The materials of construction for the CO_2 Storage, Fire Protection/Purge System components are:

- Aluminum
- Copper alloy
- Copper alloy (>15% Zn or >8% Al)
- Elastomer
- Glass
- High-strength steel
- Nickel Alloy
- Stainless steel
- Steel

Environments

The CO_2 Storage, Fire Protection/Purge System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air, condensation
- Any
- Condensation
- Gas

Aging Effects Requiring Management

The following aging effects associated with the CO_2 Storage, Fire Protection/Purge System components require management:

- Cracking
- 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 CO_2 Storage, Fire Protection/Purge System components:

- Bolting Integrity (B.2.1.10)
- Fire Protection (B.2.1.15)
- Fire Water System (B.2.1.16)
- One-Time Inspection (B.2.1.20)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- TLAA (Section 4.3)

3.3.2.1.14 Station Drainage System

Materials

The materials of construction for the Station Drainage System components are:

- Copper alloy
- Copper alloy (>15% Zn or >8% Al)
- Gray cast iron, ductile iron
- High-strength steel
- Stainless steel
- Steel

Environments

The Station Drainage System components are exposed to the following environments:

- Air
- Air - outdoor
- Air - indoor uncontrolled
- Air, condensation
- Waste water

Aging Effects Requiring Management

The following aging effects associated with the Station Drainage System components 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 Station Drainage System components:

- Bolting Integrity (B.2.1.10)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)

3.3.2.1.15 Sampling and Water Quality System

Materials

The materials of construction for the Sampling and Water Quality System components are:

- Cast austenitic stainless steel
- Copper alloy
- Copper alloy (>15% Zn or >8% Al)
- Glass
- Gray cast iron, ductile iron
- High-strength steel
- Nickel alloy
- Polymeric
- Stainless steel
- Steel

Environments

The Sampling and Water Quality System components are exposed to the following environments:

- Air
- Air - indoor controlled
- Air - indoor uncontrolled
- Air - outdoor
- Air, condensation
- Any
- Condensation
- Gas
- Raw Water
- Reactor coolant
- Reactor coolant >250°C (>482°F)
- Treated water
- Treated water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects associated with the Sampling and Water Quality System components require management:

- Cracking
- Hardening or loss of strength
- Flow blockage
- Loss of fracture toughness
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following aging management programs manage the aging effects for the Sampling and Water Quality System components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- Water Chemistry (B.2.1.2)
- Bolting Integrity (B.2.1.10)
- Open-Cycle Cooling Water System (B.2.1.11)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- TLAA (Section 4.3)

3.3.2.1.16 Building Heating System

Materials

The materials of construction for the Building Heating System components are:

- Copper Alloy
- High-strength steel
- Steel

Environments

The Building Heating System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air, condensation
- Any
- Closed-cycle cooling water
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the Building Heating System components 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 Building Heating System components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)

3.3.2.1.17 Hypochlorite System

Materials

The materials of construction for the Hypochlorite System components are:

- High-strength steel
- Nickel Alloy
- Polymeric
- Stainless Steel
- Steel

Environments

The Hypochlorite System components are exposed to the following environments:

- Air
- Air - outdoor
- Condensation
- Raw Water

Aging Effects Requiring Management

The following aging effects associated with the Hypochlorite System components require management:

- Cracking
- 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 Hypochlorite System components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)

3.3.2.1.18 Demineralizer Backwash Air System

Materials

The materials of construction for the Demineralizer Backwash Air System components are:

- Cast Iron
- Copper Alloy
- High-strength steel
- Steel

Environments

The Demineralizer Backwash Air System components are exposed to the following environments:

- Air
- Air - dry
- Air - indoor uncontrolled
- Air, condensation
- Condensation

Aging Effects Requiring Management

The following aging effects associated with the Demineralizer Backwash Air System components require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the Demineralizer Backwash Air System components:

- Bolting Integrity (B.2.1.10)
- Compressed Air Monitoring (B.2.1.14)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)

3.3.2.1.19 Standby Liquid Control System

Materials

The materials of construction for the Standby Liquid Control System components are:

- Aluminum
- Copper alloy
- High-strength steel
- Stainless steel
- Steel

Environments

The Standby Liquid Control System components are exposed to the following environments:

- Air
- Air - indoor controlled
- Air - indoor uncontrolled
- Air, condensation
- Lubricating oil
- Reactor coolant
- Sodium pentaborate solution
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the Standby Liquid Control System components require management:

- Cracking due to SCC
- 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 Standby Liquid Control System components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- Water Chemistry (B.2.1.2)
- Bolting Integrity (B.2.1.10)
- One-Time Inspection (B.2.1.20)
- ASME Code Class 1 Small-bore Piping (B.2.1.22)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)

- Lubricating Oil Analysis (B.2.1.25)
- TLAA (Section 4.3)

3.3.2.1.20 Off-Gas System

Materials

The materials of construction for the Off-Gas System components are:
- Copper Alloy
- High-strength steel
- Stainless steel
- Steel

Environments

The Off-Gas System components are exposed to the following environments:
- Air
- Air - indoor uncontrolled
- Air, Condensation
- Condensation

Aging Effects Requiring Management

The following aging effects associated with the Off-Gas System components 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 Off-Gas System components:
- Bolting Integrity (B.2.1.10)
- One-Time Inspection (B.2.1.20)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- TLAA (Section 4.3)

3.3.2.1.21 Emergency Equipment Cooling Water System

Materials

The materials of construction for the Emergency Equipment Cooling Water System components are:

- Aluminum
- Copper Alloy
- Copper alloy (>15% Zn or >8% Al)
- Gray cast iron, ductile iron
- High-strength steel
- Stainless steel
- Steel

Environments

The Emergency Equipment Cooling Water Systemm components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air - outdoor
- Air, condensation
- Concrete
- Gas
- Raw Water
- Soil

Aging Effects Requiring Management

The following aging effects associated with the Emergency Equipment Cooling Water System components require management:

- Cracking due to SCC
- Cumulative fatigue damage
- Long-term loss of material
- 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 Emergency Equipment Cooling Water System components:

- Bolting Integrity (B.2.1.10)
- Open-Cycle Cooling Water System (B.2.1.11)
- One-Time Inspection (B.2.1.20)

- Selective Leaching (B.2.1.21)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Buried and Underground Piping and Tanks (B.2.1.27)
- TLAA (Section 4.3)

3.3.2.1.22 Reactor Water Cleanup System

Materials

The materials of construction for the Reactor Water Cleanup System components are:

- Cast austenitic stainless steel
- Copper alloy
- Copper alloy (>15% Zn or >8% Al)
- Glass
- Gray cast iron, ductile iron
- High-strength steel
- Stainless Steel
- Steel

Environments

The Reactor Water Cleanup System components are exposed to the following environments:

- Air
- Air - indoor Controlled
- Air - indoor uncontrolled
- Air, condensation
- Condensation
- Gas
- Reactor coolant
- Reactor coolant >250°C (>482°F)
- Treated Water
- Treated water >60°C (>140°F)
- Treated water >93°C (>200°F)

Aging Effects Requiring Management

The following aging effects associated with the Reactor Water Cleanup System components require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of fracture toughness
- 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 Reactor Water Cleanup System components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- Water Chemistry (B.2.1.2)
- BWR Stress Corrosion Cracking (B.2.1.5)
- Flow-Accelerated Corrosion (B.2.1.9)
- Bolting Integrity (B.2.1.10)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- ASME Code Class 1 Small-bore Piping (B.2.1.22)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- TLAA (Section 4.3)

3.3.2.1.23 Reactor Building Closed Cooling Water System

Materials

The materials of construction for the Reactor Building Closed Cooling Water System components are:

- Aluminum
- Copper alloy
- Copper alloy (>15% Zn or >8% Al)
- High-strength steel
- Nickel Alloy
- Stainless steel
- Steel

Environments

The Reactor Building Closed Cooling Water System components are exposed to the following environments:

- Air
- Air - dry
- Air - indoor uncontrolled
- Air, Condensation
- Closed cooling (treated) water
- Closed-cycle cooling water

- Condensation
- Gas
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the Reactor Building Closed Cooling Water System components require management:

- Cracking
- Loss of material
- Loss of preload
- Wall thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Building Closed Cooling Water System components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- Compressed Air Monitoring (B.2.1.14)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)

3.3.2.1.24 Auxiliary Decay Heat Removal System

Materials

The materials of construction for the Auxiliary Decay Heat Removal System components are:

- High-strength steel
- Stainless steel
- Steel

Environments

The Auxiliary Decay Heat Removal System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air, Condensation
- Closed-cycle cooling water
- Gas

Aging Effects Requiring Management

The following aging effects associated with the Auxiliary Decay Heat Removal System components 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 Auxiliary Decay Heat Removal System components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- One-Time Inspection (B.2.1.20)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)

3.3.2.1.25 Containment Inerting System

Materials

The materials of construction for the Containment Inerting System components are:

- Aluminum
- Copper Alloy
- High-strength steel
- Nickel Alloy
- Stainless Steel
- Steel

Environments

The Containment Inerting System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air - outdoor
- Air, condensation
- Condensation
- Gas

Aging Effects Requiring Management

The following aging effects associated with the Containment Inerting System components require management:

- Cracking

- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the Containment Inerting System components:

- Bolting Integrity (B.2.1.10)
- One-Time Inspection (B.2.1.20)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)

3.3.2.1.26 Radwaste System

Materials

The materials of construction for the Radwaste System components are:

- Copper Alloy
- Copper alloy (>15% Zn or >8% Al)
- Elastomer
- High-strength steel
- Metallic
- Stainless steel
- Steel

Environments

The Radwaste System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air - outdoor
- Air, Condensation
- Concrete
- Gas
- Lubricating oil
- Treated Water
- Treated water >60°C (>140°F)
- Waste water

Aging Effects Requiring Management

The following aging effects associated with the Readwaste System components require management:

- Cracking

- 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 Radwaste System components:

- Water Chemistry (B.2.1.2)
- Bolting Integrity (B.2.1.10)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Buried and Underground Piping and Tanks (B.2.1.27)

3.3.2.1.27 Spent Fuel Cooling/Cleanup System

Materials

The materials of construction for the Spent Fuel Cooling/Cleanup System components are:

- Aluminum
- Gray cast iron, ductile iron
- High-strength steel
- Stainless steel
- Steel

Environments

The Spent Fuel Cooling/Cleanup System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air - outdoor
- Air, condensation
- Concrete
- Treated Water
- Waste water

Aging Effects Requiring Management

The following aging effects associated with the Spent Fuel Cooling/Cleanup System components 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 Spent Fuel Cooling/Cleanup System components:

- Water Chemistry (B.2.1.2)
- Bolting Integrity (B.2.1.10)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)

3.3.2.1.28 Fuel Handling and Storage System

Materials

The materials of construction for the Fuel Handling and Storage System components are:

- Aluminum
- Boral®; boron steel, and other materials (excluding Boraflex)
- High-strength steel
- Stainless Steel
- Steel

Environments

The Fuel Handling and Storage System components are exposed to the following environments:

- Air
- Treated water
- Treated water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects associated with the Fuel Handling and Storage System components require management:

- Cracking
- Loss of material
- Loss of preload
- Reduction of neutron-absorbing capacity

Aging Management Programs

The following aging management programs manage the aging effects for the Fuel Handling and Storage System components:

- Water Chemistry (B.2.1.2)

- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)
- Monitoring of Neutron-Absorbing Materials other than Boraflex (B.2.1.26)

3.3.2.1.29 Standby Diesel Generators

Materials

The materials of construction for the Standby Diesel Generators components are:

- Aluminum
- Copper Alloy
- Copper alloy (>15% Zn or >8% Al)
- Elastomer
- Glass
- Gray cast iron, ductile iron
- High-strength steel
- Stainless Steel
- Steel

Environments

The Standby Diesel Generators components are exposed to the following environments:

- Air
- Air - indoor controlled
- Air - indoor uncontrolled
- Air - outdoor
- Closed-cycle cooling water
- Condensation
- Diesel exhaust
- Gas
- Lubricating oil
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the Standby Diesel Generators components require management:

- Cracking
- Cumulative fatigue damage
- Hardening or loss of strength
- Loss of material
- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following aging management programs manage the aging effects for the Standby Diesel Generators components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Lubricating Oil Analysis (B.2.1.25)
- TLAA (Section 4.3)

3.3.2.1.30 Supplemental Diesel Generator System

Materials

The materials of construction for the Supplemental Diesel Generator System components are:

- Aluminum
- Elastomer
- High-strength steel
- Stainless Steel
- Steel

Environments

The Supplemental Diesel Generator System System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air - outdoor
- Air, Condensation
- Closed-cycle cooling water
- Diesel Exhaust
- Fuel Oil
- Lubrication Oil

Aging Effects Requiring Management

The following aging effects associated with the Supplemental Diesel Generator System System components require management:

- Cracking
- Hardening or loss of strength
- Loss of material

- Loss of preload
- Reduction of heat transfer

Aging Management Programs

The following aging management programs manage the aging effects for the Supplemental Diesel Generator System components:

- Bolting Integrity (B.2.1.10)
- Closed Treated Water Systems (B.2.1.12)
- Fuel Oil Chemistry (B.2.1.18)
- One-Time Inspection (B.2.1.20)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Lubricating Oil Analysis (B.2.1.25)

3.3.2.1.31 Control Rod Drive System

Materials

The materials of construction for the Control Rod Drive System components are:

- Aluminum
- Copper alloy
- Copper alloy (>15% Zn or >8% Al)
- High-strength steel
- Stainless steel
- Steel

Environments

The Control Rod Drive System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air - outdoor
- Air, Condensation
- Any
- Lubricating oil
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the Control Rod Drive System components 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 Control Rod Drive System components:

- Water Chemistry (B.2.1.2)
- Bolting Integrity (B.2.1.10)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Lubricating Oil Analysis (B.2.1.25)
- TLAA (Section 4.3)

3.3.2.1.32 Diesel Generator Starting Air System

Materials

The materials of construction for the Diesel Generator Starting Air System components are:

- Aluminum
- Copper Alloy
- Copper alloy (>15% Zn or >8% Al)
- Elastomer
- Glass
- High-strength steel
- Stainless Steel
- Steel

Environments

The Diesel Generator Starting Air System components are exposed to the following environments:

- Air
- Air-dry
- Air - indoor controlled
- Air - indoor uncontrolled
- Air - outdoor
- Condensation
- Lubricating Oil

Aging Effects Requiring Management

The following aging effects associated with the Diesel Generator Starting Air System components require management:

- Cracking due to SCC
- 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 Diesel Generator Starting Air System components:

- Bolting Integrity (B.2.1.10)
- Compressed Air Monitoring (B.2.1.14)
- One-Time Inspection (B.2.1.20)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Lubricating Oil Analysis (B.2.1.25)

3.3.2.1.33 Cranes and Hoists

Materials

The materials of construction for the Cranes and Hoists components are:

- High-strength steel
- Stainless Steel
- Steel

Environments

The Cranes and Hoists components are exposed to the following environments:

- Air

Aging Effects Requiring Management

The following aging effects associated with the Cranes and Hoists components require management:

- Cumulative fatigue damage
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the Cranes and Hoists components:

- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)
- TLAA (Section 4.7)

3.3.2.1.34 Sewage System

Materials

The materials of construction for the Sewage System components are:

- Not Applicable

Environments

The Sewage System components are exposed to the following environments:

- Not Applicable

Aging Effects Requiring Management

The following aging effects associated with the Sewage System components require management:

- None

Aging Management Programs

The following aging management programs manage the aging effects for the Sewage System components:

- None

3.3.2.1.35 FLEX System

Materials

The materials of construction for the FLEX System components are:

- High-strength steel
- Stainless Steel
- Steel

Environments

The FLEX System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air - outdoor
- Air, Condensation
- Raw Water

Aging Effects Requiring Management

The following aging effects associated with the FLEX System components require management:

- Cracking
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the FLEX System components:

- Bolting Integrity (B.2.1.10)
- Open-Cycle Cooling Water System (B.2.1.11)
- One-Time Inspection (B.2.1.20)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)

3.3.2.1.36 Security System

Materials

The materials of construction for the Security System components are:

- Not Applicable

Environments

The Security System components are exposed to the following environments:

- Not Applicable

Aging Effects Requiring Management

The following aging effects associated with the Security System components require management:

- None

Aging Management Programs

The following aging management programs manage the aging effects for the Security System components:

- None

3.3.2.1.37 Radiation Monitoring System

Materials

The materials of construction for the Radiation Monitoring System components are:

- Aluminum
- Copper alloy

- Copper alloy (>15% Zn or >8% Al)
- Glass
- High-strength steel
- Polymeric
- Stainless Steel
- Steel

Environments

The Radiation Monitoring System components are exposed to the following environments:

- Air
- Air- indoor controlled
- Air - indoor uncontrolled
- Air - outdoor
- Air, Condensation
- Any
- Closed-cycle cooling water >60°C (>140°F)
- Closed-cycle cooling water
- Gas
- Raw Water
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the Radiation Monitoring System components require management:

- Cracking
- 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 Radiation Monitoring System components:

- Water Chemistry (B.2.1.2)
- Bolting Integrity (B.2.1.10)
- Open-Cycle Cooling Water System (B.2.1.11)
- Closed Treated Water Systems (B.2.1.12)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)

- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)
- TLAA (Section 4.3)

3.3.2.1.38 Hardened Containment Venting System

Materials

The materials of construction for the Hardened Containment Venting System components are:
- Steel

Environments

The Hardened Containment Venting System components are exposed to the following environments:
- Air - indoor uncontrolled
- Air - outdoor
- Underground

Aging Effects Requiring Management

The following aging effects associated with the Hardened Containment Venting System components require management:
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the Hardened Containment Venting System components:
- Bolting Integrity (B.2.1.10)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Buried and Underground Piping and Tanks (B.2.1.27)

3.3.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL-SLR Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the subsequent license renewal application. For the Auxiliary Systems, those programs are addressed in the following subsections.

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.

Table 3.3.1 Item Number 3.3-1, 001: This item evaluates steel cranes: rails, bridges, structural members, structural components exposed to the environments of air-indoor uncontrolled and air-outdoor for cumulative fatigue damage due to fatigue. Cumulative fatigue damage is evaluated and dispositioned as a TLAA for the Cranes and Hoists System as discussed in Section 4.7.

Table 3.3.1 Item Number 3.3-1, 002: This item evaluates piping, piping components exposed to the environments of diesel exhaust and treated water for cumulative fatigue damage due to fatigue. Cumulative fatigue damage is evaluated and dispositioned as a TLAA for the Emergency High Pressure Makeup, Auxiliary Boiler, High Pressure Fire Protection (Diesel Driven Pump), Off-Gas, Emergency Equipment Cooling Water, Standby Diesel Generator, Standby Liquid Control, Residual Heat Removal Service Water, CO_2 Storage Fire Protection/Purge, Control Rod Drive, Sampling and Water Quality, Radiation Monitoring, and Reactor Water Cleanup Systems, as discussed in Section 4.3.

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.

Table 3.3.1 Item Numbers 3.3-1, 003 and 3.3-1, 003a: These Item Numbers are applicable to PWRs only and are not used for BFN.

3.3.2.2.3 Cracking Due to Stress Corrosion Cracking in Stainless Steel Alloys

Cracking due to SCC could occur in indoor or outdoor SS piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated, (b) insulated, (c) in the vicinity of insulated components, or (d) in the vicinity of potentially transportable halogens. Cracking can occur in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS components exposed to indoor air, outdoor air, condensation, or underground environments are susceptible to SCC if the insulation contains certain contaminants. Leakage of fluids through bolted connections (e.g., flanges, valve packing) can result in contaminants present in the insulation leaching onto the component surface or the surfaces of other *components below the component. For outdoor insulated SS components, rain and changing weather conditions can result in moisture intrusion into the insulation.*

Plant-specific OE and the condition of SS components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in SCC. SCC in SS components is not an aging effect requiring management if (a) plant-specific OE does not reveal a history of SCC and (b) a one-time inspection demonstrates that the aging effect is not occurring.

In the environment of air-indoor controlled, SCC is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations.

The applicant documents the results of the plant-specific OE review in the license renewal application (LRA).

The GALL-SLR Report recommends further evaluation of SS piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of SCC. The GALL-SLR Report AMP XI.M32, “One-Time Inspection,” describes an acceptable program to demonstrate that SCC is not occurring. If SCC is applicable, the following AMPs describe acceptable programs to manage loss of material due to SCC: (a) GALL-SLR Report AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks,” for tanks; (b) GALL-SLR Report AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” for external surfaces of piping and piping components; (c) GALL-SLR Report AMP XI.M41, “Buried and Underground Piping and Tanks,” for underground piping, piping components and tanks; and (d) GALL-SLR Report AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,” for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the “detection of aging effects” program element in GALL-SLR Report AMP XI.M32.

The applicant may establish that SCC is not an aging effect requiring management for all components, by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks,” describes an acceptable program to manage the integrity of a barrier coating.

<u>Table 3.3.1 Item Number 3.3-1, 004:</u> This item evaluates cracking due to SCC in stainless steel components exposed to air-indoor uncontrolled, air-outdoor, and condensation environments. There are stainless steel components exposed to an environment of air-indoor controlled in BFN Auxiliary Systems. Stainless steel components within the screened-in portions of the Auxiliary Systems are in the following systems: Emergency High Pressure Makeup, Auxiliary Boiler, Fuel Oil, Residual Heat Removal Service Water, Raw Cooling Water, Raw Service Water, High Pressure Fire Protection (Diesel Driven Pump), Potable Water, Air Conditioning, Service Air, Sampling and Water Quality, Hypochlorite, Reactor Building Closed Cooling Water, Reactor

Water Cleanup, Standby Diesel Generators, Radiation Monitoring, Diesel Generator Starting Air and the Diverse and Flexible Coping Strategies (FLEX) Systems.

BFN OE associated with stainless steel components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environments of air-indoor uncontrolled, air-outdoor, and condensation has resulted in cracking due to SCC. Cracking has been identified as an aging effect at BFN for stainless steel in these environments, or as a result of transportable halogens, indicating that the environments do contain sufficient halides (e.g., chlorides) in the presence of moisture to result in SCC in the Diesel Generator Starting Air System. This is a conservative assumption based on a lack of information as to the apparent or root cause of the component failure. While there are no known widespread sources of halogens that are inherent to the design of the systems within the EDG building, the fact that the waterproof doors open to an outdoor environment during maintenance, creates the possibility of inadvertently introducing halogens through cross contamination of soil or even deicing salt with components inside the EDG building. Accordingly, BFN will implement the External Surfaces Monitoring of Mechanical Components program (B.2.1.23) to demonstrate that the aging effect of cracking is not occurring in piping, piping components, and tanks exposed to air-indoor uncontrolled, air-outdoor, and condensation for the Diesel Generator Starting Air System.

BFN will implement the One-Time Inspection program (B.2.1.20) to demonstrate that the aging effect of cracking is not occurring in piping, piping components, and tanks exposed to air-indoor uncontrolled, air-outdoor, and condensation for the Emergency High Pressure Makeup, Auxiliary Boiler, Fuel Oil, Residual Heat Removal Service Water, Raw Cooling Water, Raw Service Water, High Pressure Fire Protection (Diesel Driven Pump), Potable Water, Air Conditioning, Service Air, Sampling and Water Quality, Hypochlorite, Reactor Building Closed Cooling Water, Reactor Water Cleanup, Standby Diesel Generators, Radiation Monitoring, and the Diverse and Flexible Coping Strategies (FLEX) Systems. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program.

<u>Table 3.3.1 Item Number 3.3-1, 094a:</u> This item evaluates cracking due to SCC in stainless steel ducting, ducting components exposed to air, condensation environments in the Air Conditioning, Normal Ventilation, Standby Gas Treatment, and Containment Systems. Plant OE associated with stainless steel ducting and ducting components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environments of air and condensation has resulted in cracking due to SCC. Cracking has not been identified as an aging effect at BFN for stainless steel ducting and ducting components exposed to air, condensation environments. Accordingly, BFN will implement the One-Time Inspection program (B.2.1.20) to demonstrate that the aging effect of cracking is not occurring in stainless steel ducting, ducting components in the Air Conditioning, Normal Ventilation, Standby Gas Treatment and Containment Systems exposed to air, condensation environments. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program.

<u>Table 3.3.1 Item Number 3.3-1, 146:</u> This item evaluates cracking due to SCC in underground stainless steel piping and piping components in the Spent Fuel Pool Cooling and Clean-up System. Plant OE associated with SCC in underground stainless steel piping and piping components has been evaluated in Spent Fuel Pool Cooling and Clean-up. SCC in underground stainless steel piping and piping components in the Spent Fuel Pool Cooling and Clean-up System has not been detected. Accordingly, BFN will implement the One-Time Inspection program (B.2.1.20) to demonstrate that the aging effect of cracking is not occurring in underground stainless steel piping and piping components in the Spent Fuel Pool Cooling and Clean-up System. Deficiencies will be documented in accordance with 10 CFR Part 50,

Appendix B Corrective Action Program. The One-Time Inspection program is described in Appendix B.

Table 3.3.1 Item Number 3.3-1, 205: This item evaluates cracking due to SCC in tanks in the Sampling and Water Quality System exposed to air and condensation environments. Design specifications for thermal insulation impose limits on leachable concentrations for chlorides and fluorides for insulation used on stainless steel so that SCC is not promoted. Plant OE associated with insulated stainless steel components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environments of air and condensation has resulted in cracking due to SCC. Cracking has not been identified as an aging effect at BFN for insulated stainless steel in these environments indicating that moisture intrusion into the insulation and leaching of contaminants present in the insulation onto component surfaces, or onto other components below the insulated component, resulting in SCC has not occurred. Accordingly, BFN will implement the One-Time Inspection program (B.2.1.20) to demonstrate that the aging effect of cracking is not occurring in tanks in the Sampling and Water Quality System exposed to air and condensation environments. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection program is described in Appendix B.

Table 3.3.1 Item Number 3.3-1, 231: Not applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks exposed to air, condensation in Auxiliary Systems.

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 GALL-SLR Report AMP XI.M32.

The applicant may establish that loss of material due to pitting and crevice corrosion is not an aging effect requiring management by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.

<u>Table 3.3.1 Item Number 3.3-1, 006:</u> This item evaluates loss of material due to pitting and crevice corrosion in stainless steel components exposed to air-indoor uncontrolled, air-outdoor, and condensation environments. There are stainless steel components exposed to an environment of air-indoor controlled in Auxiliary Systems. There are no nickel alloy components in the Auxiliary Systems. Stainless steel components within the screened-in portions of the Auxiliary Systems are in the following systems: Emergency High Pressure Makeup, Auxiliary Boiler, Fuel Oil, Raw Cooling Water, High Pressure Fire Protection (Diesel Driven Pump), Potable Water, Air Conditioning, Control Air, Carbon Dioxide, Sampling and Water Quality, Hypochlorite, Off-Gas, Standby Liquid Control, Emergency Equipment Cooling Water, Reactor Water Cleanup, Reactor Building Closed Cooling Water, Auxiliary Decay Heat Removal, Containment Inerting, Radiation Monitoring, Radwaste, Spent Fuel Pool Cooling/Cleanup, Supplemental Diesel Generator, Control Rod Drive, and Diverse and Flexible Coping Strategies (FLEX) Systems. Plant OE associated with stainless steel components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environments of air-indoor uncontrolled, air-outdoor, and condensation has resulted in loss of material due to pitting and crevice corrosion. OE identified loss of material on stainless steel components in the following systems: Air Conditioning (AC), Emergency Equipment Cooling Water (EECW), Reactor Water

Cleanup (RWCU), Auxiliary Decay Heat Removal (ADHR) and Control Rod Drive (CRD) systems.

BFN will implement the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) for the internal portions of these components in the Air Conditioning system. BFN will implement the One-Time Inspection program (B.2.1.20) to demonstrate that the aging effect of loss of material is not occurring on the external surfaces in the Air Conditioning system. BFN will implement the External Surfaces Monitoring of Mechanical Components program (B.2.1.23) to demonstrate that the aging effect will be adequately managed for the EECW system. BFN will implement the External Surfaces Monitoring of Mechanical Components program (B.2.1.23) to demonstrate that the aging effect will be adequately managed for the RWCU system. BFN will implement the External Surfaces Monitoring of Mechanical Components program (B.2.1.23) and the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) to demonstrate that the aging effect will be adequately managed for the CRD system.

BFN will implement the One-Time Inspection program (B.2.1.20) to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion in stainless steel components exposed to air-indoor uncontrolled, air-outdoor, and condensation environments for the Auxiliary Boiler, Fuel Oil, Raw Cooling Water, High Pressure Fire Protection (Diesel Driven Pump), Potable Water, Air Conditioning, Control Air, Carbon Dioxide, Sampling, Hypochlorite, Off-Gas, Emergency Equipment Cooling Water, Reactor Building Closed Cooling Water, Auxiliary Decay Heat Removal, Containment Inerting, Radiation Monitoring, Radwaste, Spent Fuel Pool Cooling/ Cleanup, Supplemental Diesel Generator, and Diverse and Flexible Coping Strategies (FLEX) Systems. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program.

<u>Table 3.3.1 Item Number 3.3-1, 094:</u> This item evaluates loss of material due to pitting, crevice corrosion in stainless steel ducting, ducting components exposed to air, condensation environments in the Air Conditioning and Normal Ventilation systems. Plant OE associated with stainless steel ducting and ducting components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environments of air and condensation has resulted in loss of material due to pitting, crevice corrosion. Loss of material due to pitting, crevice corrosion has not been identified as an aging effect at BFN for stainless steel ducting and ducting components exposed to air, condensation environments in the Air Conditioning, Normal Ventilation, and Standby Gas Treatment and Containment Systems. Accordingly, BFN will implement the One-Time Inspection program (B.2.1.20) program to demonstrate that the aging effect of evaluates loss of material due to pitting, crevice corrosion is not occurring in stainless steel ducting, ducting components in the Air Conditioning, Normal Ventilation, Standby Gas Treatment and Containment Systems exposed to air, condensation environments. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program.

<u>Table 3.3.1 Item Number 3.3-1, 222:</u> This item evaluates loss of material due to pitting and crevice corrosion in stainless steel tanks exposed to air-indoor uncontrolled and condensation environments. There are no stainless steel tanks exposed to an environment of air-indoor controlled in the Auxiliary Systems. There are no nickel alloy tanks in the Auxiliary Systems. Plant OE associated with stainless steel components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environments of air-indoor uncontrolled and condensation has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at BFN for stainless steel in these environments, or as a result of transportable halogens, indicating that these environments do not

contain sufficient halides (e.g., chlorides) in the presence of moisture to result in loss of material. Accordingly, BFN will implement the One-Time Inspection program (B.2.1.20) to demonstrate that the aging effect of loss of material is not occurring in stainless steel components exposed to air- indoor uncontrolled and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program.

<u>Table 3.3.1 Item Number 3.3-1, 228:</u> Not applicable. There are no stainless steel, nickel alloy tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air, condensation in Auxiliary Systems.

<u>Table 3.3.1 Item Number 3.3-1, 232:</u> This item evaluates loss of material due to pitting and crevice corrosion in insulated stainless steel components exposed to air-outdoor and condensation environments in the Standby Liquid Control, Emergency Equipment Cooling Water, Reactor Water Cleanup, Containment Inerting, Spent Fuel Pool Cleaning/Cleanup and Control Rod Drive systems. Plant OE associated with insulated stainless steel components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environments of air-outdoor and condensation has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at BFN for insulated stainless steel in these environments indicating that moisture intrusion into the insulation and leaching of contaminants present in the insulation onto component surfaces, or onto other components below the insulated component, resulting in loss of material has not occurred. Accordingly, BFN will implement the One-Time Inspection program (B.2.1.20) to demonstrate that the aging effect of loss of material is not occurring in insulated stainless steel piping and piping components exposed to air- outdoor and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program.

<u>Table 3.3.1 Item Number 3.3-1, 241:</u> This item evaluates loss of material due to pitting and crevice corrosion in stainless steel heat exchanger components exposed to an air- indoor uncontrolled environment in the Sampling and Water Quality, Auxiliary Decay Heat Removal, Containment Inerting, and Containment Atmosphere Dilution Systems. Plant OE associated with stainless steel components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environment of air-indoor uncontrolled has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at BFN for stainless steel in this environment, or as a result of transportable halogens, indicating that this environment does not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in loss of material. Accordingly, BFN will implement the One-Time Inspection program (B.2.1.20) to demonstrate that the aging effect of loss of material is not occurring in stainless steel heat exchanger components exposed to air-indoor uncontrolled in the Sampling and Water Quality, Auxiliary Decay Heat Removal, Containment Inerting, and Containment Atmosphere Dilution Systems. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program.

<u>Table 3.3.1 Item Number 3.3-1, 246:</u> This item evaluates loss of material due to pitting, crevice corrosion in underground stainless steel piping and piping components in the Spent Fuel Pool Cooling and Clean-up System. Plant OE associated with loss of material due to pitting, crevice corrosion in underground stainless steel piping and piping components has been evaluated in Spent Fuel Pool Cooling and Clean-up. Loss of material due to pitting, crevice corrosion in underground stainless steel piping and piping components in the Spent Fuel Pool Cooling and Clean-up System has not been detected. Accordingly, BFN will implement the One-Time Inspection program (B.2.1.20) to demonstrate that the aging effect of loss of material is not occurring in underground stainless steel piping and piping components in the Spent Fuel Pool

Cooling and Clean-up System. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program.

3.3.2.2.5 Quality Assurance for Aging Management of Nonsafety-Related Components

QA provisions applicable to Subsequent License Renewal are discussed in Appendix A, Section A.1.4, and Appendix B, Section B.1.3.

3.3.2.2.6 Ongoing Review of Operating Experience

Ongoing review of operating experience is addressed in Appendix A, Section A.1.5, and Appendix B, Section B.1.4.

3.3.2.2.7 Loss of Material Due to Recurring Internal Corrosion

Recurring internal corrosion can result in the need to augment AMPs beyond the recommendations in the GALL-SLR Report. During the search of plant-specific OE conducted during the SLRA development, recurring internal corrosion can be identified by the number of occurrences of aging effects and the extent of degradation at each localized corrosion site. This further evaluation item is applicable if the search of plant specific OE reveals repetitive occurrences. The criteria for recurrence is (a) a 10 year search of plant specific OE reveals the aging effect has occurred in three or more refueling outage cycles; or (b) a 5 year search of plant specific OE reveals the aging effect has occurred in two or more refueling outage cycles and resulted in the component either not meeting plant specific acceptance criteria or experiencing a reduction in wall thickness greater than 50 percent (regardless of the minimum wall thickness).

The GALL-SLR Report recommends that GALL-SLR Report AMP XI.M20, “Open-Cycle Cooling Water System,” GALL-SLR Report AMP XI.M27, “Fire Water System,” or GALL- SLR Report AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,” be evaluated for inclusion of augmented requirements to ensure the adequate management of any recurring aging effect(s). Alternatively, a plant-specific AMP may be proposed. Potential augmented requirements include: alternative examination methods (e.g., volumetric versus external visual), augmented inspections (e.g., a greater number of locations, additional locations based on risk insights based on susceptibility to aging effect and consequences of failure, a greater frequency of inspections), and additional trending parameters and decision points where increased inspections would be implemented.

The applicant states: (a) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (b) the basis for the adequacy of augmented or lack of augmented inspections, (c) what parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (d) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (e) how leaks in any involved buried or underground components will be identified.

Plant-specific OE examples should be evaluated to determine if the chosen AMP should be augmented even if the thresholds for significance of aging effect or frequency of occurrence of aging effect have not been exceeded. For example, during a 10-year search of plant-specific OE, two instances of 360 degree 30 percent wall loss occurred at copper alloy to steel joints. Neither the significance of the aging effect nor the frequency of occurrence of aging effect threshold has been exceeded. Nevertheless, the OE should be evaluated to determine if the AMP that is *proposed to manage the aging effect is sufficient (e.g., method of inspection, frequency of inspection, number of inspections) to provide reasonable assurance that the current licensing basis (CLB) intended functions of the component will be met throughout the subsequent period of extended operation. While recurring internal corrosion is not as likely in other environments as raw water and waste water (e.g., treated water), the aging effect should be addressed in a similar manner.*

Table 3.3.1 Item Number 3.3-1, 127: The review of plant specific OE has identified no recurring internal corrosion in metallic piping, piping components, tanks exposed to raw water, raw water (potable), treated water, or waste water in the screened in portions of Raw Cooling Water, Raw Service Water, RHR Service Water, High Pressure Fire Protection, and Emergency Equipment Coolant Water Systems. However, since internal Operating Experience has shown that there have been significant numbers of piping through wall leaks and/or minimum wall thickness readings within the BFN raw water systems, recurring internal corrosion is assumed. Therefore, as described below, BFN will implement the Open-Cycle Cooling Water System program (B.2.1.11) to manage recurring internal corrosion in the piping, piping components, tanks exposed to raw water, raw water (potable), treated water, or waste water systems. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The Open-Cycle Cooling Water System program is described in Appendix B.

The Open Cycle Cooling Program is controlled by a BFN procedure for Raw Water Fouling and Corrosion Control. This procedure defines and implements responsibilities and requirements of TVA Nuclear Power Group Standard Programs and Process procedure for Raw Water Corrosion Program and the applicable BFN Generic Letter 89-13 actions required to mitigate raw water fouling and corrosion related degradation in RHRSW, EECW, and raw water systems. The details of responsible organizations, inspection and testing requirements, and chemical treatment are specified in BFN procedure. The BFN procedure utilizes visual inspections, nondestructive testing (i.e., ultrasonic testing, and eddy current testing), material for corrosion and deposit control, and heat exchanger and component cleaning on a periodic basis to measure surface conditions and the extent of wall thinning.

With regard to normally inaccessible piping, piping components (i.e., buried, underground), Opportunistic internal visual inspections are conducted to identify loss of material, fouling, and cracking prior to loss of intended function.

Heat transfer capabilities are verified through inspection and cleaning whenever a raw water system is opened. Preventive maintenance work orders direct the cleaning, maintenance, and testing of raw water systems and components. System engineering performs inspections on all GL 89-13 components, completes required evaluations, and along with the heat exchanger coordinator, performs damage assessment and corrective action determination for heat exchangers.

In addition to being covered by the Open Cycle Cooling Water System Program, as described below, BFN will implement the Fire Water System program (B.2.1.16) to manage the potential for recurring internal corrosion in the Fire Water System. The Fire Water System Program applies to water-based fire protection systems that consist of sprinklers, nozzles, fittings, valves, hydrants, hose stations, standpipes, water storage tanks, and aboveground and underground piping and components that are tested in accordance with the applicable National Fire Protection Association codes and standards. The Fire Water System tests are mandated by the BFN NFPA 805 Fire Protection Report, which is incorporated by reference into the BFN FSAR.

Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The Fire Water System program is described in Appendix B.

The continued implementation of the Open-Cycle Cooling Water System program (B.2.1.11) and Fire Water System program (B.2.1.16) provide reasonable assurance that the aging effects will be managed so that the systems and components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

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.

<u>Susceptible Material:</u> *If the material is not susceptible to SCC then cracking is not an aging effect requiring management. The microstructure of an aluminum alloy, of which alloy composition is only one factor, is what determines if the alloy is susceptible to SCC. Therefore, determining susceptibility based on alloy composition alone is not adequate to conclude whether a particular material is susceptible to SCC. The temper, condition, and product form of the alloy is considered when assessing if a material is susceptible to SCC. Aluminum alloys that are susceptible to SCC include:*

- *2xxx series alloys in the F, W, Ox, T3x, T4x, or T6x temper*
- *5xxx series alloys with a magnesium content of 3.5 weight percent or greater*
- *6xxx series alloys in the F temper*
- *7xxx series alloys in the F, T5x, or T6x temper*
- *2xx.x and 7xx.x series alloys*
- *3xx.x series alloys that contain copper*
- *5xx.x series alloys with a magnesium content of greater than 8 weight percent*

The material is evaluated to verify that it is not susceptible to SCC and that the basis used to make the determination is technically substantiated. Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys.

Aluminum alloy and temper combination which are not susceptible to SCC when used in piping, piping component, and tank applications include 1xxx series, 3xxx series, 6061-T6x, and 5454-x. If it is determined that a material is not susceptible to SCC, the SLRA provides the components/locations where it is used, alloy composition, temper or condition, product form, and for tempers not addressed above, the basis used to determine the alloy is not susceptible and technical information substantiating the basis.

<u>Aggressive Environment:</u> *If the environment to which an aluminum alloy is exposed is not aggressive, such as dry gas or treated water, then cracking due to SCC will not occur and it is not an aging effect requiring management. Aggressive environments that are known to result in*

cracking due to SCC of susceptible aluminum alloys are aqueous solutions, air, condensation, and underground locations that contain halides (e.g., chloride). Halide concentrations should be considered high enough to facilitate SCC of aluminum alloys in uncontrolled or untreated aqueous solutions and air, such as raw water, waste water, condensation, underground locations, and outdoor air, unless demonstrated otherwise.

Halides could be present on the surface of the aluminum material if the component is encapsulated in a material such as insulation or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, sufficient halide concentrations to cause SCC could be present due to secondary sources such as leakage from nearby components (e.g., leakage from insulated flanged connections or valve packing). If an aluminum component is exposed to a halide-free indoor air environment, not encapsulated in materials containing halides, and the exposure to secondary sources of moisture or halides is precluded, cracking due to SCC is not expected to occur. The plant-specific configuration can be used to demonstrate that exposure to halides will not occur. If it is determined that SCC will not occur because the environment is not aggressive, the SLRA provides the components and locations exposed to the environment, a description of the environment, basis used to determine the environment is not aggressive, and technical information substantiating the basis. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," and a review of plant-specific OE describe an acceptable means to confirm the absence of moisture or halides within the proximity of the aluminum component.

If the environment potentially contains halides, GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," describes an acceptable program to manage cracking due to SCC of aluminum tanks. GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking due to SCC of aluminum piping and piping components. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage cracking due to SCC of aluminum piping and tanks which are buried or underground. GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," describes an acceptable program to manage cracking due to SCC of aluminum components that are not included in other AMPs.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent SCC. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

<u>Table 3.3.1 Item Number 3.3-1, 186:</u> Not applicable. There are no 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 screened in portions of BFN Auxiliary Systems.

<u>Table 3.3.1 Item Number 3.3-1, 189:</u> This item evaluates cracking due to SCC in aluminum piping, piping components, tanks exposed to air, condensation, raw water, raw water (potable), or waste water environments. There are aluminum alloy components exposed to these environments in screened in portions of BFN Auxiliary Systems. Aluminum piping, piping components, tanks exposed to air, condensation, raw water, raw water (potable), waste water within the screened-in portions of the Auxiliary Systems are located in the following systems:

Fuel Oil, CO_2 Storage Fire Protection/Purge, Containment, Standby Liquid Control, Reactor Building Closed Cooling Water and Radiation Monitoring Systems. The component types in the identified systems are exposed to air, condensation, raw water, raw water (potable) or waste water and are constructed of aluminum alloys that are susceptible to SCC, or assumed susceptible to SCC because the specific series of the aluminum alloy is unknown. Therefore, SCC is a predicted aging effect and aging management of these components for SCC is required. Plant OE associated with aluminum alloy components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environment of air, condensation, raw water, raw water (potable) or waste water would result in cracking due to SCC from halide exposure. Cracking has not been identified as an aging effect at BFN for aluminum alloy in this environment, or as a result of exposure to secondary sources, confirming the absence of moisture or halides within the proximity of the aluminum alloy components. Accordingly, BFN will implement the One-Time Inspection program (B.2.1.20) to demonstrate that the aging effect of cracking is not occurring in the aluminum alloy piping and piping components identified above that are susceptible to SCC and exposed to air, condensation, raw water, raw water (potable) or waste water. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection program is described in Appendix B.

Table 3.3.1 Item Number 3.3-1, 192: Not applicable. There are no aluminum underground piping, piping components, and tanks in screened in portions of BFN Auxiliary Systems.

Table 3.3.1 Item Number 3.3-1, 233: There are insulated aluminum piping, piping components, and tanks exposed to air and condensation in screened in portions of the High Pressure Fire Protection System (Diesel water heater tank for the gate 2 diesel driven fire pump) for BFN Auxiliary Systems. Plant OE associated with insulated aluminum piping, piping components, and tanks in the screened in portions of BFN Auxiliary Systems has been evaluated to determine if prolonged exposure to air and condensation environment will result in cracking due to stress corrosion cracking (SCC). SCC has not been identified as an aging effect at BFN for insulated aluminum piping, piping components, and tanks in this environment. Accordingly, BFN will implement the One-Time Inspection program (B.2.1.20) to demonstrate that the aging effect of cracking is not occurring in the insulated aluminum alloy piping and piping components and tanks identified above that are susceptible to SCC and exposed to air, condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection program is described in Appendix B.

Table 3.3.1 Item Number 3.3-1, 254: Not Applicable. There are no aluminum heat exchanger components exposed to air or condensation susceptible to cracking in screened in portions of the BFN Auxiliary Systems. A review of BFN OE and work orders for the coolers identified no instances where aluminum alloys in an air/gas environment had an aging related failure mechanism for any components in the screened in portions of BFN Auxiliary Systems. However, in Engineered Safety Features Systems, components have been aligned to this Item Number, and include the aluminum alloy for the Core Spray and RHR Room Cooler fins. These flat plate fins are constructed of an aluminum alloy for which the specific type was not determined. Pure aluminum is not susceptible to SCC, however, aluminum alloys containing more than 12% zinc or more than 6% magnesium are very susceptible to cracking under mild corrosive environments. Aluminum alloys are susceptible to SCC in air and water vapor environments as well as in corrosive environment containing chloride solutions and saltwater. Generally, a wetted condition is required to cause SCC. The air/gas environment for the Core Spray and RHR room coolers does not contain the level of moisture necessary to be considered a wetted environment nor does the environment have chloride solutions or saltwater. SCC is not a concern for aluminum and aluminum alloys related to BFN Auxiliary Systems.

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.

<u>Table 3.3.1 Item Number 3.3-1, 112:</u> Loss of material for steel piping and piping components with an external environment of concrete can occur for components in the Auxiliary Systems that are potentially exposed to groundwater at the soil-concrete interface. BFN will manage loss of material for steel piping and piping components exposed to concrete (and potentially exposed to groundwater) in the Auxiliary Systems with the Buried and Underground Piping and Tanks program (B.2.1.27). Steel components within the screened-in portions of the Auxiliary Systems are located in the following systems: Fuel Oil, Residual Heat Removal Service Water, High Pressure Fire Protection (Diesel Driven Pump), Emergency Equipment Cooling Water, Radwaste and Spent Fuel Pool Cooling/Cleanup Systems. The Auxiliary Systems includes steel piping and tanks exposed to concrete. A review of OE for BFN indicates there are occurrences of concrete degradation, in some systems, that could lead to the penetration of water to the metal surface; therefore, a loss of material due to general, pitting, and crevice corrosion of steel piping and tanks exposed to concrete is an aging effect that requires management. It should be noted that some systems within the Auxiliary Systems have steel components exposed to concrete (e.g., Fuel Oil and Spent Fuel Pool Cooling/Cleanup Systems) but are located indoors and shielded from an outdoor environment which would not require aging management. Consistent with the recommendation of GALL-SLR, the Buried and Underground Piping and Tanks program (B.2.1.27) is used to manage loss of material in steel piping and tanks exposed to concrete. This program provides for the management of aging effects. Any evidence of loss of material will be

evaluated for acceptability. Conditions will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. Loss of material aging effect is addressed is by Table 3.3-1 item 3.3-1, 109. These aging effects are managed by the Buried and Underground Piping and Tanks program, as described in Appendix B.

Table 3.3.1 Item Number 3.3-1, 202: Stainless steel piping, piping components exposed to concrete in the Spent Fuel Pool Cooling/Cleanup System components are indoor and not exposed to groundwater, therefore loss of material and cracking are considered to be not applicable aging effects. Loss of material for SS piping and piping components with an external environment of concrete can occur for components in the Auxiliary Systems that are potentially exposed to groundwater at the soil-concrete interface. BFN will manage loss of material for SS piping and piping components exposed to concrete (and potentially exposed to groundwater) in the Auxiliary Systems with the Buried and Underground Piping and Tanks program (B.2.1.27). The loss of material is addressed by Item Number 3.3-1, 107. Cracking is addressed by Item Number 3.3-1, 144. These aging effects are managed by the Buried and Underground Piping and Tanks program, as described in Appendix B

The Auxiliary Systems includes Stainless Steel piping and tanks exposed to concrete. A review of OE for BFN indicates there are occurrences of concrete degradation, in some systems, that could lead to the penetration of water to the metal surface; therefore, a loss of material due to general, pitting, and crevice corrosion of stainless-steel piping and tanks exposed to concrete is an aging effect that requires management. It should be noted that some systems within the Auxiliary Systems have SS and steel components exposed to concrete (e.g., Spent Fuel Pool Cooling/Cleanup System), but are located indoors and shielded from an outdoor environment which would not require aging management. The Buried and Underground Piping and Tanks program (B.2.3.27) is used to manage loss of material in steel piping and tanks exposed to concrete. This program provides for the management of aging effects. Any evidence of loss of material will be evaluated for acceptability. Conditions will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The Buried and Underground Piping and Tanks program is described in Appendix B.

3.3.2.2.10 Loss of Material Due to Pitting and Crevice Corrosion in Aluminum Alloys

Loss of material due to pitting and crevice corrosion could occur in aluminum piping, piping components, and tanks exposed to an air, condensation, underground, raw water, or waste water environment for a sufficient duration of time. Environments that can result in pitting and/or crevice corrosion of aluminum alloys are those that contain halides (e.g., chloride) in the presence of moisture. The moisture level and halide concentration in atmospheric and uncontrolled air are greatly dependent on geographical location and site-specific conditions. Moisture level and halide concentration should be considered high enough to facilitate pitting and/or crevice corrosion of aluminum alloys in atmospheric and uncontrolled air, unless demonstrated otherwise. The periodic introduction of moisture or halides into an environment from secondary sources should also be considered. Leakage of fluids from mechanical connections (e.g., insulated bolted flanges and valve packing); onto a component in indoor controlled air is an example of a secondary source that should be considered. Halide concentrations should be considered high enough to facilitate loss of material of aluminum alloys in untreated aqueous solutions, unless demonstrated otherwise. Plant-specific OE and the condition of aluminum alloy components are evaluated to determine if prolonged exposure to the plant-specific air, condensation, underground, or water environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for aluminum alloys if (a) plant-specific OE does not reveal a history of loss of material due to *pitting or crevice corrosion and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components. The applicant documents the results of the plant-specific OE review in the SLRA.*

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Alloy susceptibility may be considered when reviewing OE and interpreting inspection results. Inspections focus on the most susceptible alloys and locations.

The GALL-SLR Report recommends the further evaluation of aluminum piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting and crevice corrosion: (i) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (ii) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (iii) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (iv) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in GALL-SLR Report AMP XI.M32.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent loss of material due to pitting and crevice corrosion. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," or equivalent program, describes an acceptable program to manage the integrity of a barrier coating.

Table 3.3.1 Item Number 3.3-1, 223: Not applicable. There are no aluminum underground piping, piping components, and tanks in screened in portions of BFN Auxiliary Systems. Plant OE associated with aluminum underground piping, piping components, and tanks in the screened in portions of BFN Auxiliary Systems has been evaluated to determine if prolonged exposure to an underground environment will result in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at BFN for aluminum underground piping, piping components, and tanks in this environment.

Table 3.3.1 Item Number 3.3-1, 227: Not applicable. There are no aluminum tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air or condensation in screened in portions of BFN Auxiliary Systems.

Table 3.3.1 Item Number 3.3-1, 234: This item evaluates loss of material due to pitting and crevice corrosion in aluminum alloy components exposed to air-indoor uncontrolled and condensation environments. There are aluminum alloy components identified for screened in portions which are exposed to an environment of air-indoor controlled in Auxiliary Systems. All components aligned to this Item Number have been evaluated and assumed to be potentially susceptible to loss of material due to pitting and crevice corrosion as a result of exposure to halides (e.g., chlorides). Aluminum alloy components within the screened-in portions of the Auxiliary Systems are located in the following systems: Fuel Oil, Residual Heat Removal Service Water, High Pressure Fire Protection (Diesel Driven Pump), Air Conditioning, Control Air, Containment, Containment Inerting, Spent Fuel Pool Cooling/Cleanup, Control Rod Drive, Radiation Monitoring and Diesel Generator Starting Air Systems. Plant OE associated with aluminum alloy components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environments of air-indoor uncontrolled and condensation will result in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at BFN in the Fuel Oil, Residual Heat Removal Service Water, High Pressure Fire Protection (Diesel Driven Pump), Air Conditioning, Control Air, Containment, Containment Inerting, Spent Fuel Pool Cooling/Cleanup, Control Rod Drive and Diesel Generator Starting Air Systems for aluminum alloy in these environments, or as a result of exposure to secondary sources, indicating that the environments do not contain sufficient halides in the presence of moisture to result in loss of material. Accordingly, BFN will implement the One-Time Inspection program (B.2.1.20) to demonstrate that the aging effect of loss of material is not occurring in aluminum alloy piping, piping components exposed to air- indoor uncontrolled and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection program is described in Appendix B.

BFN OE review identified loss of material on aluminum alloy components in the Radiation Monitoring System. Accordingly, BFN will implement the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) for the internal portions of these components in the Radiation Monitoring System. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is described in Appendix B.

Table 3.3.1 Item Number 3.3-1, 240: Not applicable. There are no aluminum heat exchanger components exposed to waste water identified in screened in portions of BFN Auxiliary Systems.

Table 3.3.1 Item Number 3.3-1, 242: This item evaluates loss of material due to pitting and crevice corrosion in aluminum alloy heat exchanger components exposed to a condensation environment. There are aluminum alloy heat exchanger components identified for screened in portions of Air Conditioning, Emergency Equipment Core Cooling, and Standby Diesel Generators of Auxiliary Systems which are exposed to the environments of air-indoor uncontrolled or air-indoor controlled in BFN Auxiliary Systems. All components aligned to this Item Number have been evaluated and assumed to be potentially susceptible to loss of material due to pitting and crevice corrosion as a result of exposure to halides (e.g., chlorides). Plant OE associated with aluminum alloy components in the Auxiliary Systems has been evaluated to determine if prolonged exposure to the environment of condensation will result in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at BFN for aluminum alloy heat exchanger components in this environment, or as a result of exposure to secondary sources, indicating that this environment does not contain sufficient halides in the presence of moisture to result in loss of material. Accordingly, BFN will implement the One-Time Inspection program (B.2.1.20) to demonstrate that the aging effect of loss of material is not occurring in aluminum alloy heat exchanger components exposed to condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection program is described in Appendix B.

Table 3.3.1 Item Number 3.3-1, 245: Not applicable. There are no insulated aluminum piping, piping components, and tanks exposed to air and condensation identified in screened in portions of BFN Auxiliary Systems.

Table 3.3.1 Item Number 3.3-1, 247: Not Applicable. There are no aluminum piping, piping components, tanks exposed to raw water, waste water identified in screened in portions of BFN Auxiliary Systems.

3.3.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Auxiliary Systems components:

- Section 4.3, Metal Fatigue Analyses
  - Section 4.3.2, Metal Fatigue of Class 1 Components
  - Section 4.3.4, Metal Fatigue of Non-Class 1 Components
  - Section 4.3.7, Emergency Equipment Cooling Water Weld Flaws Evaluation
- Section 4.7, Other Plant-Specific Analyses
  - Section 4.7.1, Reactor Building Crane Cyclic Loading

3.3.3 Conclusion

The Auxiliary Systems components that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Auxiliary Systems components are identified in the summaries in Section 3.3.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the subsequent period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Auxiliary Systems components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the current licensing basis during the subsequent period of extended operation.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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	Consistent with NUREG-2191. Fatigue is a TLAA; further evaluation is documented in Subsection 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	Consistent with NUREG-2191. Fatigue is a TLAA; further evaluation is documented in Subsection 3.3.2.2.1.
3.3-1, 003	PWR Only				
3.3-1, 003a	PWR Only				

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage cracking of stainless steel piping, piping components, and tanks exposed to air- indoor uncontrolled, air-outdoor, and condensation program will be used to manage cracking of stainless steel heat exchanger components, piping, piping components, and tanks exposed to air and condensation. Impacted systems include, Emergency High Pressure Makeup, Auxiliary Boiler, Fuel Oil, Residual Heat Removal Service Water, Raw Cooling Water, Raw Service Water, High Pressure Fire Protection (Diesel Driven Pump), Potable Water, Air Conditioning, Service Air, Sampling and Water Quality, Hypochlorite, Radiation Monitoring, Reactor Building Closed Cooling Water, Reactor Water Cleanup, Standby Diesel Generators and FLEX Systems. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage cracking of stainless steel piping, piping components, and tanks exposed to air and condensation. Impacted systems include the Diesel Generator Starting Air System. See Subsection 3.3.2.2.3.
3.3-1, 005	This Item Number is not used in NUREG-2192.				

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 006	Stainless steel, nickel alloy piping, piping components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, “One-Time Inspection,” AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,” or AMP XI.M42, “Internal Coatings/ Linings for In- Scope Piping, Piping Components, Heat Exchangers, and Tanks”	Yes	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage loss of material in stainless steel piping, piping components, and tanks exposed to air-indoor uncontrolled, air and condensation. Impacted systems include, Emergency High Pressure Makeup, Auxiliary Boiler, Fuel Oil, Raw Cooling Water, High Pressure Fire Protection (Diesel Driven Pump), Potable Water, Air Conditioning (external surfaces), Control Air, CO_2 Storage Fire Protection/ Purge, Emergency Equipment Cooling Water, Sampling and Water Quality, Hypochlorite, Off-Gas, Reactor Building Closed Cooling Water, Auxiliary Decay Heat Removal, Containment Inerting, Radiation Monitoring, Radwaste, Spent Fuel Pool Cooling/Cleanup, Supplemental Diesel Generator, Standby Liquid Control, FLEX Systems. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage loss of material in stainless steel piping, piping components exposed to air and condensation for the Emergency Equipment Cooling Water, Reactor Water Cleanup and Control Rod Drive Systems. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) will be used to manage loss of material in stainless steel piping, piping components exposed to air and condensation in the Air Conditioning and Control Rod Drive Systems. See Subsection 3.3.2.2.4.
3.3-1, 007	PWR Only				
3.3-1, 008	PWR Only				

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 009	PWR Only				
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	Consistent with NUREG-2191. The Bolting Integrity program (B.2.1.10) will be used to manage cracking due to SCC, cyclic loading of high-strength steel closure bolting exposed to air, soil, underground within the screened-in portions of the Emergency High Pressure Makeup, Auxiliary Boiler, Fuel Oil, Residual Heat Removal Service Water, Raw Cooling Water, Raw Service Water, High Pressure Fire Protection (Diesel Driven Pump), Potable Water, Normal Ventilation, Air Conditioning, Control Air, Service Air, CO_2 Storage Fire Protection/Purge, Station Drainage, Sampling and Water Quality, Building Heating, Hypochlorite, Demineralizer Backwash Air, Standby Liquid Control, Off-Gas, Emergency Equipment Cooling Water, Radiation Monitoring, Reactor Water Cleanup, Reactor Building Closed Cooling Water, Auxiliary Decay Heat Removal, Containment Inerting, Radwaste, Spent Fuel Pool Cooling/Cleanup, Standby Diesel Generators, Supplemental Diesel Generator, Control Rod Drive, Diesel Generator Starting Air and FLEX Systems.
3.3-1, 011	This Item Number is not used in NUREG-2192.				

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 012	Steel; stainless steel, nickel alloy closure bolting exposed to air – indoor uncontrolled, air –outdoor, condensation	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M18, “Bolting Integrity”	No	Consistent with NUREG-2191. The Bolting Integrity program (B.2.1.10) will be used to manage loss of material of carbon and low alloy steel and stainless steel closure bolting exposed to air-indoor uncontrolled, air-outdoor, and condensation in the Emergency High Pressure Makeup, Auxiliary Boiler, Fuel Oil, Radiation Monitoring, Residual Heat Removal Service Water, Raw Cooling Water, Raw Service Water, High Pressure Fire Protection (Diesel Driven Pump), Potable Water, Normal Ventilation, Air Conditioning, Control Air, Service Air, CO_2 Storage Fire Protection/Purge, Station Drainage, Sampling and Water Quality, Building Heating, Hypochlorite, Demineralizer Backwash Air, Standby Liquid Control, Off-Gas, Emergency Equipment Cooling Water, Reactor Water Cleanup, Reactor Building Closed Cooling Water, Auxiliary Decay Heat Removal, Containment Inerting, Radwaste, Spent Fuel Pool Cooling/Cleanup, Standby Diesel Generators, Supplemental Diesel Generator, Control Rod Drive, Diesel Generator Starting Air, Hardened Containment Venting, and FLEX Systems.
3.3-1, 013	This Item Number is not used in NUREG-2192.				
3.3-1, 014	This Item Number is not used in NUREG-2192.				

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 015	Metallic closure bolting exposed to any environment, soil, underground	Loss of preload due to thermal effects, gasket creep, self- loosening	AMP XI.M18, “Bolting Integrity”	No	Consistent with NUREG-2191. The Bolting Integrity program (B.2.1.10) will be used to manage loss of preload of carbon and low alloy steel and stainless steel closure bolting exposed to any environment, soil, underground in screened in portions of Emergency High Pressure Makeup, Auxiliary Boiler, Fuel Oil, Residual Heat Removal Service Water, Raw Cooling Water, Raw Service Water, High Pressure Fire Protection (Diesel Driven Pump), Potable Water, Normal Ventilation, Air Conditioning, Control Air, Service Air, CO_2 Storage Fire Protection/ Purge, Station Drainage, Sampling and Water Quality, Building Heating, Hypochlorite, Demineralizer Backwash Air, Standby Liquid Control, Off-Gas, Emergency Equipment Cooling Water, Reactor Water Cleanup, Reactor Building Closed Cooling Water, Auxiliary Decay Heat Removal, Containment Inerting, Radiation Monitoring, Radwaste, Spent Fuel Pool Cooling/ Cleanup, Standby Diesel Generators, Supplemental Diesel Generator, Control Rod Drive, Diesel Generator Starting Air, Hardened Containment Venting, and FLEX Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 016	Stainless steel piping, piping components outboard the second containment isolation valves with a diameter ≥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	Consistent with NUREG-2191. BFN will use the Water Chemistry program (B.2.1.2) to monitor and manage the aging effects of cracking due to SCC, IGSCC on stainless steel piping, piping components outboard the second containment isolation valves with a diameter ≥4 inches nominal pipe size exposed to treated water >93°C (>200°F) in screened in portion of Reactor Water Cleanup System. BFN has satisfactorily completed all actions requested in NRC Generic Letter 88-01 for the Reactor Water Cleanup System on Units 1, 2 and 3. BFN Units 1, 2 and 3 have replaced the Reactor Water Cleanup piping with piping made of material that is resistant to IGSCC (316NG) stainless steel. The BFN Chemistry Control Program is in accordance with EPRI TR1016579 (2008 revision) BWR Water Chemistry Guidelines, which maintains a high water purity thereby reducing susceptibility to SCC. Since the piping in the Reactor Water Cleanup System is made of material that is resistant to IGSCC has been implemented, no IGSCC inspections are required.
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	Not Applicable. There are no stainless steel heat exchanger tubes exposed to treated water or treated borated water with an aging effect of reduction of heat transfer in screened in portions of Auxiliary Systems.
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. There are no stainless steel high-pressure pump casing, piping, piping components, and tanks exposed to treated borated water >60°C (>140°F) or sodium pentaborate solution >60°C (>140°F) in Auxiliary Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191. BFN will use the Water Chemistry program (B.2.1.2) to monitor and manage the aging effects of cracking due to SCC, IGSCC on stainless steel piping, piping components outboard the second containment isolation valves with a diameter ≥4 inches nominal pipe size exposed to treated water >93°C (>200°F) in screened in portion of Reactor Water Cleanup System. BFN has satisfactorily completed all actions requested in NRC Generic Letter 88-01 for the Reactor Water Cleanup System on Units 1, 2 and 3. BFN Units 1, 2 and 3 have replaced the Reactor Water Cleanup piping with piping made of material that is resistant to IGSCC (316NG) stainless steel. The BFN Chemistry Control Program is in accordance with EPRI TR1016579 (2008 revision) BWR Water Chemistry Guidelines, which maintains a high water purity thereby reducing susceptibility to SCC. Since the piping in the Reactor Water Cleanup System is made of material that is resistant to IGSCC has been implemented, no IGSCC inspections are required.
3.3-1, 020	Stainless steel, steel with stainless steel cladding heat exchanger components exposed to treated borated water >60°C (>140°F), treatedwater >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, “Water Chemistry,” and AMP XI.M32, “One Time Inspection”	No	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) and Water Chemistry program (B.2.1.2) will be used to manage cracking of carbon or low alloy steel with stainless steel cladding and stainless steel heat exchanger components exposed to treated water > 140 F in the Sampling and Water Quality, Reactor Water Cleanup, Radwaste, Reactor Feedwater, Condensate/Demineralized Water and Residual Heat Removal Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) and Water Chemistry program (B.2.1.2) will be used to manage loss of material due to general, pitting, crevice corrosion, MIC in steel piping, piping components exposed to treated water in the Emergency High Pressure Makeup, Residual Heat Removal Service Water, Sampling and Water Quality, Reactor Water Cleanup, Radwaste, Control Rod Drive Systems.
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) and Water Chemistry program (B.2.1.2) will be used to manage loss of material of the copper alloy heat exchanger components, piping, piping components exposed to treated water in the Auxiliary Boiler, Reactor Core Isolation Cooling, High Pressure Coolant Injection, Reactor Water Cleanup, Residual Heat Removal, Radwaste, and Sampling and Water Quality Systems.
3.3-1, 023	This Item Number is not used in NUREG-2192.				
3.3-1, 024	This Item Number is not used in NUREG-2192.				
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) and Water Chemistry program (B.2.1.2) will be used to manage loss of material of the aluminum piping, piping components exposed to treated water, treated borated water in the Residual Heat Removal Service Water, Standby Liquid Control, Spent Fuel Pool Cooling/Cleanup, Control Rod Drive Systems and Reactor Buildings.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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. This component, material, environment, and aging effect combination is addressed by Item Number 3.3-1, 203.
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. There are no stainless steel heat exchanger tubes exposed to treated water with an aging effect / mechanism of reduction of heat transfer due to fouling in screened in portions of Auxiliary Systems.
3.3-1, 028	PWR Only				
3.3-1, 029	This Item Number is not used in NUREG-2192.				
3.3-1, 030	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to raw water	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; flow blockage due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System"	No	Not Applicable. There are no concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to raw water with an aging effect / mechanism of 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 in screened in portions of Auxiliary Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 030a	Fiberglass, HDPE piping, piping components exposed to raw water	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture; flow blockage due to fouling	AMP XI.M20, “Open-Cycle Cooling Water System”	No	Not Applicable. There are no fiberglass, HDPE piping, piping components exposed to raw water in screened in portions of Auxiliary Systems.
3.3-1, 031	This Item Number is not used in NUREG-2192.				
3.3-1, 032	This Item Number is not used in NUREG-2192.				
3.3-1, 032a	This Item Number is not used in NUREG-2192.				
3.3-1, 033	This Item Number is not used in NUREG-2192.				
3.3-1, 034	Nickel alloy, copper alloy piping, piping components exposed to raw water	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, “Open-Cycle Cooling Water System”	No	Consistent with NUREG-2191. The Open-Cycle Cooling Water System program (B.2.1.11) will be used to manage flow blockage and loss of material of the copper alloy piping, piping components in the Radiation Monitoring, Residual Heat Removal Service Water, Raw Cooling Water, Raw Service Water, Hypochlorite, Emergency Equipment Cooling Water Systems.
3.3-1, 035	This Item Number is not used in NUREG-2192.				
3.3-1, 036	This Item Number is not used in NUREG-2192.				

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. The Open-Cycle Cooling Water System program (B.2.1.11) will be used to manage flow blockage and loss of material of the carbon steel, ductile iron, and gray cast iron heat exchanger components, piping, piping components exposed to raw water in the Residual Heat Removal Service Water, Raw Cooling Water, Raw Service Water, Sampling and Water Quality, Hypochlorite, Emergency Equipment Cooling Water, and FLEX Systems.
3.3-1, 038	Copper alloy, steel heat exchanger components exposed to raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, “Open-Cycle Cooling Water System”	No	Consistent with NUREG-2191. The Open-Cycle Cooling Water System program (B.2.1.11) will be used to manage flow blockage and loss of material of the carbon steel and copper alloy heat exchanger components exposed to raw water in the High Pressure Fire Protection (Diesel Driven Pump), Raw Cooling Water and Emergency Equipment Cooling Water Systems
3.3-1, 039	This Item Number is not used in NUREG-2192.				
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 CoolingWater System”	No	Consistent with NUREG-2191. The Open-Cycle Cooling Water System program (B.2.1.11) will be used to manage flow blockage and loss of material of the carbon or low alloy steel with stainless steel cladding and stainless steel heat exchanger components, piping, piping components, and tanks exposed to raw water in the Radiation Monitoring, Residual Heat Removal Service Water, Raw Cooling Water, Raw Service Water, Sampling and Water Quality, Hypochlorite, Emergency Equipment Cooling Water, and FLEX Systems.
3.3-1, 041	This Item Number is not used in NUREG-2192.				

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 042	Copper alloy, titanium, stainless steel heat exchanger tubes exposed to raw water, raw water (potable), treated water	Cracking due to SCC (titanium only), reduction of heat transfer due to fouling	AMP XI.M20, “Open-Cycle Cooling Water System,” or AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Consistent with NUREG-2191. The Open-Cycle Cooling Water System program (B.2.1.11) will be used to manage reduction of heat transfer of the copper alloy and stainless steel heat exchanger tubes exposed to raw water in the Emergency Equipment Cooling Water, Raw Cooling Water, Raw Service Water and Residual Heat Removal Service Water Systems.
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. The Closed Treated Water Systems program (B.2.1.12) will be used to manage aging of stainless steel piping, piping components exposed to closed-cycle cooling water >140°F in the screened-in portions of the Radiation Monitoring System.
3.3-1, 044	Stainless steel; steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, “Closed Treated Water Systems”	No	Not Applicable. There are no stainless steel; steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water >60°C (>140°F) that are susceptible to cracking due to SCC in screened in portions of Auxiliary Systems.
3.3-1, 045	Steel piping, piping components, tanks exposed to closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, “Closed Treated Water Systems”	No	Consistent with NUREG-2191. The Closed Treated Water Systems program (B.2.1.12) will be used to manage loss of material of the carbon steel and gray cast iron heat exchanger components, piping, piping components, and tanks exposed to closed-cycle cooling water in the Air Conditioning, Building Heating, Reactor Building Closed Cooling Water, Standby Diesel Generators and Supplemental Diesel Generator Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 046	Steel, copper alloy heat exchanger components, piping, piping components exposed to closed-cycle cooling water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC	AMP XI.M21A, “Closed Treated Water Systems”	No	Consistent with NUREG-2191. The Closed Treated Water Systems program (B.2.1.12) will be used to manage loss of material of the carbon steel, copper alloy, and gray cast iron heat exchanger components, piping, piping components exposed to closed-cycle cooling water in the High Pressure Fire Protection, Air Conditioning, Building Heatjng, Reactor Building Closed Cooling Water, Standby Diesel Generators and Supplemental Diesel Generator Systems.
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	Consistent with NUREG-2191. The Closed Treated Water Systems program (B.2.1.12) will be used to manage loss of material of the stainless steel heat exchanger components exposed to closed-cycle cooling water in the Auxiliary Decay Heat Removal System.
3.3-1, 048	Aluminum piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion	AMP XI.M21A, “Closed Treated Water Systems”	No	Not Applicable. There are no aluminum piping, piping components exposed to closed-cycle cooling water >140°F in the screened-in portions of the Auxiliary Systems.
3.3-1, 049	Stainless steel piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, “Closed Treated Water Systems”	No	Consistent with NUREG-2191. The Closed Treated Water Systems program (B.2.1.12) will be used to manage loss of material of the stainless steel heat exchanger components, piping, piping components exposed to closed-cycle cooling water in the Auxiliary Decay Heat Removal, Air Conditioning, Radiation Monitoring and Standby Diesel Generators Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 050	Stainless steel, copper alloy, steel heat exchanger tubes exposed to closed-cycle cooling water	Reduction of heat transfer due to fouling	AMP XI.M21A, “Closed Treated Water Systems”	No	Consistent with NUREG-2191. The Closed Treated Water Systems program (B.2.1.12) will be used to manage reduction of heat transfer of the copper alloy heat exchanger tubes exposed to closed-cycle cooling water in the High Pressure Fire Protection (Diesel Driven Pump), Standby Diesel Generators, Building Heat and Supplemental Diesel Generator Systems.
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. Boraflex is not used for neutron absorption in the BFN spent fuel storage pools. Also see Item Number 3.3-1, 102.
3.3-1, 052	Steel cranes: rails, bridges, structural members, structural components exposed to air	Loss of material due to general corrosion,wear, deformation, cracking	AMP XI.M23, “Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems”	No	Consistent with NUREG-2191. The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program (B.2.1.13) will be used to manage cracking, deformation, and loss of material of the carbon steel crane/hoist and cranes: rails, bridges, structural members, and structural components exposed to air in the Cranes and Hoists and Fuel Handling and Storage Systems.
3.3-1, 053	This Item Number is not used in NUREG-2192.				
3.3-1, 054	This Item Number is not used in NUREG-2192.				

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) will be used to manage loss of material of the carbon steel, ductile iron, and gray cast iron piping, piping components, and tanks exposed to condensation in the Control Air, Service Air, Sampling and Water Quality, Demineralizer Backwash Air, Off-Gas, Reactor Water Cleanup, Reactor Building Closed Cooling Water, Containment Inerting, Standby Diesel Generators and Diesel Generator Starting Air Systems.
3.3-1, 056	This Item Number is not used in NUREG-2192.				
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. The Fire Protection program (B.2.1.15) will be used to manage hardening and loss of strength, shrinkage due to elastomer degradation of the elastomer fire barriers exposed to air-indoor uncontrolled as shown in Table 3.5.2-36 of Structural Commodities (Hazard Barriers and Elastomers).
3.3-1, 058	Steel halon/carbon dioxide fire suppression system piping, piping components exposed to air – indoor uncontrolled,air – outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M26, “Fire Protection”	No	Consistent with NUREG-2191. The Fire Protection program (B.2.1.15) will be used to manage loss of material of the carbon steel, ductile iron, galvanized steel, and gray cast iron fire barriers, piping, piping components, and tanks exposed to air- indoor uncontrolled, air-outdoor, and condensation in the High Pressure Fire Protection (Diesel Driven Pump), and CO_2 Storage Fire Protection/Purge Systems.
3.3-1, 059	Steel fire rated doors exposed to air	Loss of material due to wear	AMP XI.M26, “Fire Protection”	No	Consistent with NUREG-2191. The Fire Protection program (B.2.1.15) will be used to manage loss of material of the carbon steel fire barrier doors exposed to air-indoor uncontrolled and air-outdoor as shown in Table 3.5.2-36 of Structural Commodities (Hazard Barriers and Elastomers).

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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. The Fire Protection program (B.2.1.15) and Structures Monitoring program (B.2.1.33) will be used to manage cracking and loss ofmaterial of the concrete and grout fire barriers and concrete elements exposed to air-indoor uncontrolled and air-outdoor as shown in Table 3.5.2-36 of Structural Commodities (Hazard Barriers and Elastomers).
3.3-1, 061	This Item Number is not used in NUREG-2192.				
3.3-1, 062	This Item Number is not used in NUREG-2192.				
3.3-1, 063	Steel fire hydrants exposed to air – outdoor, raw water, raw water (potable), treated water	Loss of material due to general, pitting, crevice corrosion; flow blockage due to fouling (raw water, raw water (potable) only)	AMP XI.M27, “Fire Water System”	No	Consistent with NUREG-2191. The Fire Water System program (B.2.1.16) will be used to manage flow blockage and loss of material of the ductile iron and gray cast iron fire hydrants exposed to air-outdoor and raw water in the High Pressure Fire Protection (Diesel Driven Pump) System.
3.3-1, 064	Steel, copper alloy piping, piping components exposed to raw water, treated water, raw water (potable)	Loss of material due to general (steel; copper alloy in raw water and raw water (potable) only), pitting, crevice corrosion, MIC; flow blockage due to fouling (raw water; raw water (potable) for steel only)	AMP XI.M27, “Fire Water System”	No	Consistent with NUREG-2191. The Fire Water System program (B.2.1.16) will be used to manage 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) in steel, copper alloy piping, piping components exposed to raw water, treated water, raw water (potable) in screened in portions of the High Pressure Fire Protection (Diesel Driven Pump) System.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 065	Aluminum piping, piping components exposed to raw water, treated water,raw water (potable)	Loss of material due to pitting, crevice corrosion; flow blockage due to fouling (raw water only)	AMP XI.M27, “Fire Water System”	No	Consistent with NUREG-2191. The Fire Water System program (B.2.1.16) will be used to manage loss of material due to pitting, crevice corrosion; flow blockage due to fouling while exposed to raw water for aluminum piping, piping components exposed to raw water, treated water, raw water (potable) in screened in portions of the High Pressure Fire Protection (Diesel Driven Pump) System.
3.3-1, 066	Stainless steel piping, piping components exposed to raw water, treated water, raw water (potable)	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling (raw water only)	AMP XI.M27, “Fire Water System”	No	Consistent with NUREG-2191. The Fire Water System program (B.2.1.16) will be used to manage flow blockage and loss of material of the stainless steel piping, piping components exposed to raw water in the High Pressure Fire Protection (Diesel Driven Pump) System.
3.3-1, 067	This Item Number is not used in NUREG-2192.				
3.3-1, 068	This Item Number is not used in NUREG-2192.				
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. The Fuel Oil Chemistry program (B.2.1.18) and One-Time Inspection program (B.2.1.20) will be used to manage loss of material of the copper alloy piping, piping components exposed to fuel oil in the Fuel Oil System. Exceptions apply to the NUREG-2191 recommendations for Fuel Oil Chemistry program (B.2.1.18) implementation.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. The Fuel Oil Chemistry program (B.2.1.18) will be used to manage loss of material of the carbon steel and gray cast iron piping, piping components, and tanks exposed to fuel oil and in the Fuel Oil, High Pressure Fire Protection (Diesel Driven Pump) and Supplement Diesel Generator Systems. Exceptions apply to the NUREG-2191 recommendations for Fuel Oil Chemistry program (B.2.1.18) implementation.
3.3-1, 071	Stainless steel, aluminum, nickel alloy piping, piping components exposed to fuel oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M30, “Fuel Oil Chemistry,” and AMP XI.M32, “One-Time Inspection,” or AMP XI.M30, “Fuel Oil Chemistry”	No	Consistent with NUREG-2191 with exceptions. The Fuel Oil Chemistry program (B.2.1.18) and One-Time Inspection program (B.2.1.20) will be used to manage loss of material of the aluminum alloy and stainless steel piping, piping components exposed to Fuel Oil System. Exceptions apply to the NUREG-2191 recommendations for Fuel Oil Chemistry program (B.2.1.18) implementation.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 072	Gray cast iron, ductile iron, copper alloy (>15% Zn or >8% Al) piping, piping components, heat exchanger components exposed to treated water, closed-cycle cooling water, soil, raw water, raw water (potable), waste water	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Consistent with NUREG-2191. The Selective Leaching program (B.2.1.21) will be used to manage loss of material of the copper alloy with greater than 15% zinc, ductile iron, and gray cast iron heat exchanger components, and piping, piping components, exposed to closed cycle cooling water, raw water, soil, treated water, and waste water in the Auxiliary Boiler, Radiation Monitoring, Residual Heat Removal Service Water, Raw Cooling Water, Raw Service Water, High Pressure Fire Protection (Diesel Driven Pump), Potable Water, Air Conditioning, Station Drainage, Sampling and Water Quality, Emergency Equipment Cooling Water, Reactor Water Cleanup, Reactor Building Closed Cooling Water, Reactor Core Isolation Cooling, High Pressure Coolant Injection, Residual Heat Removal, Core Spray, Radwaste, Spent Fuel Pool Cooling/ Cleanup, Standby Diesel Generators, and Control Rod Drive Systems.
3.3-1, 073	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to air – outdoor	Cracking due to chemical reaction, weathering, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, or scaling	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Applicable. There are no concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to air – outdoor in screened in portions of Auxiliary Systems.
3.3-1, 074	This Item Number is not used in NUREG-2192.				
3.3-1, 075	This Item Number is not used in NUREG-2192.				

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 076	Elastomer piping, piping components, ducting, ducting components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage hardening and loss of strength of the elastomer piping, piping components, ducting, ducting components, seals exposed to air and condensation in the Fuel Oil, Raw Cooling Water, High Pressure Fire Protection (Diesel Driven Pump), Normal Ventilation, Containment, Radwaste, Standby Diesel Generators, Supplemental Diesel Generator, Diesel Generator Starting Air Systems, and Table 3.5.2-36: Structural Commodities (Hazard Barriers and Elastomers).
3.3-1, 077	This Item Number is not used in NUREG-2192.				
3.3-1, 078	Steel external surfaces exposed to air – indoor uncontrolled, air – outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage loss of material of the carbon steel, ductile iron, galvanized steel, and gray cast iron ducting, ducting components, heat exchanger components, piping, piping components, and tanks exposed to air-indoor uncontrolled, air- outdoor, and condensation in the Emergency High Pressure Makeup, Fuel Oil, Potable Water, Normal Ventilation, Air Conditioning, CO_2 Storage Fire Protection/Purge, Building Heating, Demineralized Backwash Air, Off-Gas, Auxiliary Boiler, Containment Inerting, Raw Cooling Water, Standby Liquid Control, Station Drainage, Reactor Water Cleanup, Reactor Building Closed Cooling Water, Spent Fuel Pool Cooling/Cleanup, Standby Diesel Generators, Supplemental Diesel Generator, Control Rod Drive, Hardened Containment Venting and FLEX Systems.
3.3-1, 079	This Item Number is not used in NUREG-2192.				

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 080	Steel heat exchanger components, piping, piping components exposed to air – indoor uncontrolled, air – outdoor	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage loss of material of the carbon steel, ductile iron, and gray cast iron heat exchanger components, piping, piping components exposed to air-indoor uncontrolled and air-outdoor in the Emergency High Pressure Makeup, Fuel Oil, Residual Heat Removal Service Water Systems, Raw Cooling Water, Raw Service Water, High Pressure Fire Protection, Air Conditioning, Emergency Equipment Cooling Water, Control Rod Drive Systems.
3.3-1, 081	This Item Number is not used in NUREG-2192.				
3.3-1, 082	Elastomer, fiberglass piping, piping components, ducting, ducting components, seals exposed to air	Loss of material due to wear	AMP XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage loss of material of the elastomer piping, piping components exposed to air-indoor uncontrolled in the Fuel Oil, Raw Cooling Water, Containment, Standby Diesel Generators, CO_2 Storage Fire Protection/Purge and Diesel Generator Starting Air Systems.
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	Not Applicable. There are no stainless steel diesel engine exhaust piping, piping components exposed to diesel exhaust in the Standby Diesel Generators System at BFN. The exhaust piping is carbon steel alloy.
3.3-1, 084	This Item Number is not used in NUREG-2192.				

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 085	Elastomer piping, piping components, seals exposed to air, condensation, closed-cycle cooling water, treated borated water, treated water, raw water,raw water (potable), waste water, gas, fuel oil, lubricating oil	Hardening or loss of strength due to elastomer degradation; flow blockage due to fouling (raw water, waste water only)	AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) will be used to manage hardening and loss of strength of the elastomer ducting, ducting components, piping, piping components exposed to closed-cycle cooling water, condensation, fuel oil, lubricating oil, raw water, treated water, and waste water in the Fuel Oil, High Pressure Fire Protection (Diesel Driven Pump), Air Conditioning, CO_2 Storage Fire Protection/ Purge, Radwaste, Standby Diesel Generators and Supplemental Diesel Generator Systems.
3.3-1, 086	This Item Number is not used in NUREG-2192.				
3.3-1, 087	This Item Number is not used in NUREG-2192.				
3.3-1, 088	Steel; stainless steel piping, piping components, diesel engine exhaust exposed to raw water (potable), diesel exhaust	Loss of material due to general (steel only), pitting, crevice corrosion, flow blockage due to fouling (steel only for raw water (potable) environment)	AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) will be used to manage loss of material of the carbon steel, gray cast iron, and stainless steel, piping, piping components, and tanks exposed to diesel exhaust and raw water inthe Potable Water, Air Conditioning, Standby Diesel Generator, and Supplemental Diesel Generator Systems.
3.3-1, 089	Steel piping, piping components exposed to condensation (internal)	Loss of material due to general, pitting, crevice corrosion	AMP XI.M27, “Fire Water System”	No	Not Applicable. There is no steel piping, piping components exposed to condensation (internal) in screened in portions of Auxiliary Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) will be used to manage loss of material of the carbon steel and galvanized steel ducting and ducting components exposed to condensation in the Normal Ventilation, Air Conditioning, CO_2 Storage Fire Protection/Purge, Emergency High Pressure Makeup, and Off-Gas Systems.
3.3-1, 091	Steel piping, piping components, heat exchanger components, tanks exposed to waste water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) will be used to manage loss of material of the carbon steel, ductile iron, galvanized steel, and gray cast iron heat exchanger components, piping, piping components, and tanks exposed to waste water in the Station Drainage and Radwaste Systems.
3.3-1, 092	This Item Number is not used in NUREG-2192.				
3.3-1, 093	Copper alloy piping, piping components exposed to raw water (potable)	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) will be used to manage loss of material of the copper alloy piping, piping components exposed to raw water in the Air Conditioning and Potable Water Systems.
3.3-1, 094	Stainless steel ducting, ducting components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	Yes	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage loss of material of the stainless steel ducting,ducting components exposed to air, condensation in the Normal Ventilation, Air Conditioning, Standby Gas Treatment and Containment Systems. See Subsection 3.3.2.2.4.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 094a	Stainless steel ducting, ducting components exposed to air, condensation	Cracking due to SCC	AMP XI.M32, “One-Time Inspection,” AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” or AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	Yes	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage cracking due to SCC of the stainless steel ducting, ducting components exposed to air, condensation in the Normal Ventilation, Standby Gas Treatment, Air Conditioning and Containment Systems. See Subsection 3.3.2.2.3.
3.3-1, 095	Copper alloy, stainless steel, nickel alloy piping, piping components, heat exchanger components, tanks exposed to waste water	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) will be used to manage loss of material of the copper alloy and stainless steel piping, piping components, and tanks exposed to waste water in the Station Drainage and Radwaste Systems.
3.3-1, 096	Elastomer piping, piping components, seals exposed to air, raw water, raw water (potable), treated water, waste water	Loss of material due to wear; flow blockage due to fouling (raw water, waste water only)	AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) will be used to manage loss of material of the elastomer piping, piping components exposed to air, raw water, raw water (potable), treated water,waste water in Raw Cooling Water, High Pressure Fire Protection, Normal Ventilation, Air Conditioning and CO_2 Storage Fire Protection/Purge Systems.
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	Not Applicable. There are no steel, aluminum, copper alloy, stainless steel, titanium heat exchanger tubes internal to components exposed toair, condensation (external) in screened in portions of Auxiliary Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 096b	Steel heat exchanger components exposed to condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Applicable. There are no steel heat exchanger components exposed to condensation in screened in portions of Auxiliary Systems.
3.3-1, 097	Steel piping, piping components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis program (B.2.1.25) and One-Time Inspection program (B.2.1.20) will be used to manage loss of material of the carbon steel and gray cast iron piping, piping components, and tanks exposed to lubricating oil in the Emergency High Pressure Makeup, Residual Heat Removal Service Water, Raw Cooling Water, High Pressure Fire Protection (Diesel Driven Pump), Standby Liquid Control, Standby Diesel Generators, Supplemental Diesel Generator, Control Rod Drive and Diesel Generator Starting Air Systems.
3.3-1, 098	Steel heat exchanger components exposed to lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M39, "Lubricating Oil Analysis," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Lubricating Oil Analysis program (B.2.1.25) and One-Time Inspection program (B.2.1.20) will be used to manage aging of steel heat exchanger components exposed to lubricating oil for loss of material due to general, pitting, crevice corrosion, MIC in the screened in portions of the Condensate/ Demineralized Water System. This component, material, environment, and aging effect combination is also addressed by Item Number 3.3-1, 257.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 099	Copper alloy, aluminum piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC (copper alloy only)	AMP XI.M39, “Lubricating Oil Analysis,” and AMP XI.M32, “One-Time Inspection”	No	Consistent with NUREG-2191. The Lubricating Oil Analysis program (B.2.1.25) and One-Time Inspection program (B.2.1.20) will be used to manage loss of material of the aluminum alloy, copper alloy, and stainless steel heat exchanger components, piping, piping components exposed to lubricating oil in the Air Conditioning, Standby Diesel Generators, Control Rod Drive, and Diesel Generator Starting Air Systems.
3.3-1, 100	Stainless steel piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M39, “Lubricating Oil Analysis,” and AMP XI.M32, “One-Time Inspection”	No	Consistent with NUREG-2191. The Lubricating Oil Analysis program (B.2.1.25) and One-Time Inspection program (B.2.1.20) will be used to manage loss of material of the stainless steel heat exchanger components, piping, piping components, and tanks exposed to lubricating oil in the Reactor Core Isolation Cooling, High Pressure Coolant Injection, and Standby Diesel Generators Systems.
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	Consistent with NUREG-2191. The Lubricating Oil Analysis program (B.2.1.25) and One-Time Inspection program (B.2.1.20) will be used to manage reduction of heat transfer due to fouling of the aluminum heat exchanger tubes exposed to lubricating oil in the Standby Diesel Generators System.
3.3-1, 102	Boral®; boron steel, and other materials (excluding Boraflex) spent fuel storage racks: neutron-absorbing sheets (PWR), spent fuel storage racks: neutron-absorbing sheets (BWR) exposed to treated borated water, treated water	Reduction of neutron-absorbing capacity; change in dimensions and loss of material due to effects of SFP environment	AMP XI.M40, “Monitoring of Neutron-Absorbing Materials Other Than Boraflex”	No	Consistent with NUREG-2191. The Monitoring of Neutron-Absorbing Materials Other Than Boraflex program (B.2.1.26) will be used to manage reduction of neutron absorbing capacity; change in dimensions and loss of material of the boral neutron absorbing sheets exposed to treated water in the spent fuel storage racks of the Fuel Handling and Storage System.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 103	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to soil, concrete	Cracking due to chemical reaction, weathering, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, or scaling	AMP XI.M41, “Buried and Underground Piping and Tanks”	No	Not Applicable. There are no concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to soil or concrete in Auxiliary Systems.
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	Not Applicable. There are no HDPE, fiberglass piping, piping exposed to soil or concrete in screened in portions of Auxiliary Systems.
3.3-1, 105	This Item Number is not used in NUREG-2192.				
3.3-1, 106	This Item Number is not used in NUREG-2192.				
3.3-1, 107	Stainless steel, nickel alloy piping, piping components exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, “Buried and Underground Piping and Tanks”	No	Not Applicable. There is no stainless steel, nickel alloy piping, piping components exposed to soil, concrete in screened in portions of Auxiliary Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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 with exceptions. The Buried and Underground Piping and Tanks program (B.2.1.27) will be used to manage loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC (super austenitic, copper alloy, stainless steel, nickel alloy; soil environment only) in the Raw Service Water and High Pressure Fire Protection (Diesel Driven Pump) Systems. Exceptions apply to the NUREG-2191 recommendations for Buried and Underground Piping and Tanks program (B.2.1.27) implementation.
3.3-1, 109	Steel piping, piping components, closure bolting exposed to soil, concrete, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, “Buried and Underground Piping and Tanks”	No	Consistent with NUREG-2191 with exceptions. The Buried and Underground Piping and Tanks program (B.2.1.27) will be used to manage loss of material of the steel piping, piping components, closure bolting, exposed to soil, concrete, and underground in the Residual Heat Removal Service Water, High Pressure Fire Protection (Diesel Driven Pump), Radwaste, Hardened Containment Venting, and Emergency Equipment Cooling Water Systems. Exceptions apply to the NUREG-2191 recommendations for Buried and Underground Piping and Tanks program (B.2.1.27) implementation.
3.3-1, 109a	This Item Number is not used in NUREG-2192.				

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. There is no nickel alloy piping, piping components greater than or equal to 4 NPS exposed to treated water >93°C (>200°F) in screened in portions of Auxiliary Systems. Cracking in stainless steel piping, piping components greater than or equal to 4 NPS exposed to treated water >93°C (>200°F) is addressed in Item Number 3.3-1, 016.
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. There is no steel structural steel exposed to air-indoor uncontrolled air that use the Structures Monitoring program (B.2.1.33) to manage aging in screened in portions of Auxiliary Systems.
3.3-1, 112	Steel piping, piping components exposed to concrete	None	None	Yes	Consistent with NUREG-2191. Steel piping, piping components exposed to concrete for this Item Number do not have an aging effect nor do they have an Aging Management Program assigned. Operating Experience was reviewed under the Further Evaluation (Subsection 3.3.2.2.9) and no Condition Reports were identified associated with the Fuel Oil, Residual Heat Removal Service Water, High Pressure Fire Protection (Diesel Driven Pump), Emergency Equipment Cooling Water, Radwaste and Spent Fuel Pool Cooling/Cleanup Systems. However, since Residual Heat Removal Service Water, High Pressure Fire Protection (Diesel Driven Pump), Radwaste and Emergency Equipment Cooling Water Systems are potentially exposed to ground water, and subject to aging management, they are addressed under the Buried and Underground Piping and Tanks program (B.2.1.27). See Item Number 3.3-1, 109 and Subsection 3.3.2.2.9.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 113	Aluminum piping, piping components exposed to gas	None	None	No	Consistent with NUREG-2191. Aluminum piping, piping components exposed to gas do not have an aging effect nor do they have an Aging Management Program assigned. This Item Number is applicable to Containment Atmosphere Dilution and Containment Inerting Systems.
3.3-1, 114	Copper alloy piping,piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191. Copper alloy piping, piping components exposed to air, condensation, gas do not have an aging effect nor do they have an Aging Management Program assigned. This Item Number is applicable to Auxiliary Boiler, Fuel Oil, Radiation Monitoring, Residual Heat Removal Service Water, Raw Service Water, High Pressure Fire Protection (Diesel Driven Pump), Air Conditioning, Control Air, Service Air, CO_2 Storage Fire Protection/Purge, Station Drainage, Sampling and Water Quality, Demineralized Backwash Air, Standby Liquid Control, Off-Gas, Emergency Equipment Cooling Water, Reactor Water Cleanup, Reactor Building Closed-Cooling Water, Containment Inerting, Radwaste, Standby Diesel Generators, Control Rod Drive, Building Heating, and Diesel Generator Starting Air Systems.
3.3-1, 115	Copper alloy, copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage	None	None	No	Not Applicable. There are no copper alloy, copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage in screened in portions of Auxiliary Systems.
3.3-1, 116	Galvanized steel piping, piping components exposed to air – indoor uncontrolled	None	None	No	Not Applicable. There are no galvanized steel piping, piping components exposed to air – indoor uncontrolled in screened in portions of Auxiliary Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 117	Glass piping elements exposed to air, lubricating oil, closed-cycle cooling water, fuel oil, raw water, treated water, treated borated water, air with borated water leakage, condensation, gas, underground	None	None	No	Consistent with NUREG-2191. 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 do not have an aging effect nor do they have an Aging Management Program assigned. This Item Number is applicable to High Pressure Fire Protection (Diesel Driven Pump), Air Conditioning, CO_2 Storage Fire Protection/Purge, Sampling and Water Quality, Radiation Monitoring, Reactor Water Cleanup, Standby Diesel Generators, Emergency Equipment Cooling Water and Diesel Generator Starting Air Systems.
3.3-1, 118	This Item Number is not used in NUREG-2192.				
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	Not Applicable. There is no nickel alloy, PVC, glass piping, piping components exposed to air with borated water leakage, air – indoor uncontrolled, condensation, waste water, raw water (potable) not previously addressed in screened in portions of Auxiliary Systems.
3.3-1, 120	Stainless steel piping, piping components exposed to air with borated water leakage, gas	None	None	No	Consistent with NUREG-2191. Stainless steel piping, piping components exposed to air with borated water leakage, gas does not have an aging effect nor does it have an AMP assigned. This SRP is applicable to Air Conditioning, CO_2 Storage Fire Protection/Purge, Reactor Water Cleanup, Reactor Building Closed Cooling Water, Auxiliary Decay Heat Removal, and Containment Inerting Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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. Steel piping, piping components exposed to air – indoor controlled, gas do not have an aging effect nor do they have an aging Management Program assigned. This Item Number is applicable to Air Conditioning, CO_2 Storage Fire Protection/Purge, Sampling and Water Quality, Standby Liquid Control, Radiation Monitoring, Reactor Water Cleanup, Reactor Building Closed Cooling Water, Standby Diesel Generators, and Diesel Generator Starting Air Systems
3.3-1, 122	Titanium heat exchanger components, piping, piping components exposed to air – indoor uncontrolled, air – outdoor	None	None	No	Not Applicable. There are no titanium heat exchanger components, piping, piping components exposed to air – indoor uncontrolled, air – outdoor not previously addressed in screened in portions of Auxiliary Systems.
3.3-1, 123	Titanium heat exchanger components other than tubes, piping and piping components exposed to raw water	Cracking due to SCC, flow blockage due to fouling	AMP XI.M20, “Open-Cycle Cooling Water System,” or AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Not Applicable. There are no titanium heat exchanger components other than tubes, piping and piping components exposed to raw water in screened in portions of Auxiliary Systems.
3.3-1, 124	Stainless steel, steel (with stainless steel or nickel alloy cladding) spent fuel storage racks (BWR), spent fuel storage racks (PWR), piping, piping components exposed to treated water >60°C (>140°F), treated borated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, “Water Chemistry,” and AMP XI.M32, “One-Time Inspection”	No	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) and Water Chemistry program (B.2.1.2) will be used to manage aging of stainless steel, steel (with stainless steel or nickel alloy cladding) for the spent fuel storage racks (BWR), piping, piping components exposed to treated water >60°C (>140°F) in Fuel Handling and Storage System.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 125	Stainless steel, steel (with stainless steel cladding), nickel alloy spent fuel storage racks (BWR), spent fuel storage racks (PWR), piping, piping components exposed to treated water, treated borated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, “Water Chemistry,” and AMP XI.M32, “One-Time Inspection”	No	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) and Water Chemistry program (B.2.1.2) will be used to manage loss of material of the stainless steel structural bolting, equipment storage racks(inside spent fuel pool and reactor well), fuel storage racks (spent fuel), and metal components exposed to treated water in Fuel Handling and Storage System.
3.3-1, 126	Metallic piping, piping components exposed to treated water, treated borated water, raw water	Wall thinning due to erosion	AMP XI.M17, “Flow-Accelerated Corrosion”	No	Consistent with NUREG-2191. The Flow-Accelerated Corrosion program (B.2.1.9) will be used to manage wall thinning of the carbon steel and stainless steel piping, piping components exposed to treated water and raw water in the Raw Cooling Water, Condensate/Demineralized Water, Emergency High Pressure Makeup, and Reactor Water Cleanup Systems.
3.3-1, 127	Metallic piping, piping components, tanks exposed to raw water, raw water (potable), treated water, waste water	Loss of material due to recurring internal corrosion	AMP XI.M20, “Open-Cycle Cooling Water System,” AMP XI.M27, “Fire Water System,” or AMP XI.M38 “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	Yes	Not Applicable. There are no metallic piping, piping components, tanks exposed to raw water,raw water (potable), treated water, waste water that have not been addressed by other more specific item numbers in screened in portions of Auxiliary Systems. See Subsection 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. There are no 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 screened in portions of Auxiliary Systems.
3.3-1, 129	This Item Number is not used in NUREG-2192.				

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 130	Metallic sprinklers exposed to air, condensation, raw water, raw water (potable), treated water	Loss of material due to general (where applicable), pitting, crevice corrosion, MIC (except for aluminum, and in raw water, raw water (potable), treated water only); flow blockage due to fouling	AMP XI.M27, “Fire Water System”	No	Consistent with NUREG-2191. The Fire Water System program (B.2.1.16) will be used to manage Loss of material due to general (where applicable), pitting, crevice corrosion, MIC (except for aluminum, and in rawwater, raw water (potable), treated water only); flow blockage due to fouling on metallic sprinklers exposed to air, condensation, raw water, raw water (potable), treated water in the High Pressure Fire Protection System.
3.3-1, 131	Steel, stainless steel, copper alloy, aluminum piping, piping components exposed to air, condensation	Flow blockage due to fouling	AMP XI.M27, “Fire Water System”	No	Consistent with NUREG-2191. The Fire Water System program (B.2.1.16) will be used to manage flow blockage of the steel, stainless steel, copper alloy, aluminum piping, piping components, and spray nozzles exposed to air, condensation in the High Pressure Fire Protection (Diesel Driven Pump) and CO_2 Storage Fire Protection/Purge Systems.
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 (steel only), pitting, crevice corrosion; cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” or AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”	No	Consistent with NUREG-2191. The External Surfaces Monitoring of MechanicalComponents program (B.2.1.23) will be used to manage loss of material due to general (steel only), pitting, crevice corrosion; cracking due to SCC (copper alloy (>15% Zn or >8% Al) only) of the insulated steel, copper alloy (>15% Zn or >8% Al), piping, piping components exposed to air, condensation in the Emergency High Pressure Makeup, Auxiliary Boiler, Residual Heat Removal Service Water, Raw Cooling Water, High Pressure Fire Protection (Diesel Driven Pump), Potable Water, Air Conditioning, Service Air, CO_2 Storage Fire Protection/Purge, Station Drainage, Emergency Equipment Cooling Water, Reactor Water Cleanup, Reactor Building Closed Cooling Water, Radwaste, Spent Fuel Pool Cooling/ Cleanup, Supplemental Diesel Generators, Standby Diesel Generators, Control Rod Drive, and Diesel Generator Starting Air Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 133	HDPE underground piping, piping components	Cracking, blistering	AMP XI.M41, “Buried and Underground Piping and Tanks”	No	Not Applicable. There are no HDPE underground piping, piping components in screened in portions of Auxiliary Systems.
3.3-1, 134	Steel, stainless steel, copper alloy piping, piping components, and heat exchanger components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) will be used to manage loss of material of the carbon steel, copper alloy, and stainless steel piping, piping components, and traveling screens exposed to raw water in the Sampling and Water Quality and FLEX Systems.
3.3-1, 135	Steel, stainless steel pump casings exposed to waste water environment	Loss of material due to general (steel only), pitting, crevice corrosion, MIC	AMP XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	Not Applicable. There are no steel, stainless steel pump casings exposed to waste water environment in screened in portions of Auxiliary Systems.
3.3-1, 136	Steel fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Loss of material due to general, pitting, crevice corrosion, MIC (raw water, raw water (potable), treated water, soil only)	AMP XI.M27, “Fire Water System”	No	Consistent with NUREG-2191. The Fire Water System program (B.2.1.16) will be used to manage loss of material of the steel fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water in the High Pressure Fire Protection (Diesel Driven Pump) System.
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. There are no 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 in screened in portions of the Auxiliary Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 138	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, treated borated water, fuel oil, lubricating oil, waste water, air-dry, air, condensation	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting,or physical damage; loss of material or cracking for cementitious coatings/ linings	AMP XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks”	No	Consistent with NUREG-2191. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (B.2.1.24) will be used to manage loss of coating or lining integrity of the carbon steel (with internal coating), ductile iron (with internal coating), galvanized steel, gray cast iron (with internal coating), and stainless steel (with internal coating) heat exchanger components, piping, piping components, and tanks exposed to lubricating oil, raw water, treated water, and waste water in the Residual Heat Removal Service Water, High Pressure Fire Protection (Diesel Driven Pump), Control Air and Service Air Systems.
3.3-1, 139	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, treated borated water, fuel oil, lubricating oil, waste water, air-dry, air, condensation	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks”	No	Consistent with NUREG-2191. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (B.2.1.24) will be used to manage loss of material due to general, pitting, crevice corrosion, MIC on any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, treated borated water, fuel oil, lubricating oil, waste water, air-dry, air, condensation in Residual Heat Removal Service Water, Control Air and Service Air Systems.
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. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (B.2.1.24) will be used to manage loss of material of the ductile iron (with internal coating) and gray cast iron (with internal coating) piping, piping components exposed to raw water in the High Pressure Fire Protection (Diesel Driven Pump) and Potable Water Systems.
3.3-1, 141	This Item Number is not used in NUREG-2192.				

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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, crevicecorrosion, MIC (raw water and waste water environments only)	AMP XI.M18, “Bolting Integrity”	No	Consistent with NUREG-2191. The Bolting Integrity program (B.2.1.10) will be used to manage loss of material of the carbon and low alloy steel and stainless steel closure bolting exposed to raw water and waste water in the Emergency High Pressure Makeup, Residual Heat Removal Service Water, High Pressure Fire Protection (Diesel Driven Pump), and Spent Fuel Pool Cooling/Cleanup Systems.
3.3-1, 143	This Item Number is not used in NUREG-2192.				
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	Not Applicable. There is no stainless steel, steel, aluminum piping, piping components, tanks exposed to soil, concrete for which cracking due to SCC (steel in carbonate / bicarbonate environment only) exist in screened in portions of the Auxiliary Systems.
3.3-1, 145	Stainless steel closure bolting exposed to air, soil, concrete, underground, waste water	Cracking due to SCC	AMP XI.M18, “Bolting Integrity”	No	Consistent with NUREG-2191. The Bolting Integrity program (B.2.1.10) will be used to manage cracking ofstainless steel closure bolting exposed to air-indoor uncontrolled and air-outdoor in the Radiation Monitoring, Station Drainage, Sampling and Water Quality, Standby Liquid Control, and Reactor Water Cleanup Systems.
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage aging for stainless steel underground piping, piping components, and tanks in screened in portions of Spent Fuel Pool Cooling/Cleanup System. See Subsection 3.3.2.2.3.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 147	Nickel alloy, nickel alloy cladding piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, "Closed Treated Water Systems"	No	Not Applicable. There is no nickel alloy, nickel alloy cladding piping, piping components exposed to closed-cycle cooling water in screened in portions of Auxiliary Systems.
3.3-1, 148	This Item Number is not used in NUREG-2192.				
3.3-1, 149	Fiberglass piping, piping components, ducting, ducting components exposed to air – outdoor	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Applicable. There is no fiberglass piping, piping components, ducting and ducting components exposed to air-outdoor in screened in portions of Auxiliary Systems.
3.3-1, 150	Fiberglass piping, piping components, ducting, ducting components exposed to air	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Not Applicable. There is no fiberglass piping, piping components, ducting, ducting components exposed to air in screened in portions of Auxiliary Systems.
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. External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage stainless steel, steel, aluminum, copper alloy, titanium heat exchanger tubes exposed to air, condensation in reduction of heat transfer due to fouling in the Air Conditioning, Sampling and Water Quality, Building Heating, Reactor Water Cleanup, Auxiliary Decay Heat Removal, Emergency Equipment Cooling Water, Supplemental Diesel Generator and Control Rod Drive Systems.
3.3-1, 152	This Item Number is not used in NUREG-2192.				
3.3-1, 153	This Item Number is not used in NUREG-2192.				

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 154	This Item Number is not used in NUREG-2192.				
3.3-1, 155	Stainless steel piping, piping components, and tanks exposed to waste water >60°C (>140°F)	Cracking due to SCC	AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Not Applicable. There are no stainless steel piping, piping components, and tanks exposed to waste water >60°C (>140°F) in screened in portions of Auxiliary Systems.
3.3-1, 156	This Item Number is not used in NUREG-2192.				
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 andDucting Components”	No	Consistent with NUREG-2191. The Fire Water System program (B.2.1.16) or Inspection of Internal Surfaces in Miscellaneous Piping andDucting Components program (B.2.1.24) will be used to manage loss of material of the steel piping, piping components exposed to air-outdoor in the High Pressure Fire Protection (Diesel Driven Pump), Normal Ventilation, Station Drainage, and Radiation Monitoring Systems.
3.3-1, 158	Nickel alloy piping, piping components heat exchanger components (for components not covered by NRC GL 89-13) exposed to raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Not Applicable. There are no nickel alloy piping, piping components heat exchanger components (for components not covered by NRC GL 89-13) exposed to raw water in screened in portions of Auxiliary Systems.
3.3-1, 159	Fiberglass piping, piping components, ducting, ducting components exposed to air	Loss of material due to wear	AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Not Applicable. There is no fiberglass piping, piping components, ducting, and ducting components exposed to air in screened in portions of Auxiliary Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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. The Open-Cycle Cooling Water System program (B.2.1.11) and Closed Treated Water Systems program (B.2.1.12) will be used to manage cracking of copper alloy with greater than 15% zinc heat exchanger components, piping, piping components exposed to raw water in the Raw Cooling Water, Raw Service Water, Emergency Equipment Cooling Water, High Pressure Fire Protection (Diesel Driven Pump), Air Conditioning and Reactor Building Closed Cooling Water Systems.
3.3-1, 161	Copper alloy heat exchanger tubes exposed to condensation	Reduction of heat transfer due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no copper alloy heat exchanger tubes exposed to condensation with a heat transfer intended function in screened in portions of Auxiliary Systems.
3.3-1, 162	This Item Number is not used in NUREG-2192.				
3.3-1, 163	This Item Number is not used in NUREG-2192.				
3.3-1, 164	This Item Number is not used in NUREG-2192.				
3.3-1, 165	This Item Number is not used in NUREG-2192.				
3.3-1, 166	Copper alloy piping, piping components exposed to concrete	None	None	No	Not Applicable. There is no copper alloy piping, piping components exposed to concrete in screened in portions of Auxiliary Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 167	Zinc piping components exposed to air-indoor controlled, air - indoor uncontrolled	None	None	No	Consistent with NUREG-2191. There is no zinc piping components exposed to air-indoor controlled, air - indoor uncontrolled in screened in portions of Auxiliary Systems. However, it is applicable to Standby Gas Treatment System.
3.3-1, 168	This Item Number is not used in NUREG-2192.				
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. The Water Chemistry program (B.2.1.2) and the One-Time Inspection program (B.2.1.20) will be used to manage the loss of material due to general (steel only), pitting, crevice corrosion of steel, copper alloy piping, piping components exposed to steam in the Auxiliary Boiler System.
3.3-1, 170	Stainless steel piping, piping components exposed to steam	Loss of material due to pitting, crevice corrosion	AMP XI.M2, “Water Chemistry,” and AMP XI.M32, “One-Time Inspection”	No	Not Applicable. There are no stainless steel piping, piping components exposed to steam in screened in portions of Auxiliary Systems.
3.3-1, 171	This Item Number is not used in NUREG-2192.				
3.3-1, 172	PVC piping, piping components exposed to air-outdoor	Reduction in impact strength due to photolysis	AMP XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	Not Applicable. There is no PVC piping, piping components exposed to air-outdoor in screened in portions of Auxiliary Systems.
3.3-1, 173	This Item Number is not used in NUREG-2192.				
3.3-1, 174	This Item Number is not used in NUREG-2192.				

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 175	Fiberglass piping, piping components, tanks exposed to raw water (for components not covered by NRC GL 89-13), raw water (potable), treated water, waste water	Cracking, blistering, loss of material due to exposure to ultraviolet light, ozone, radiation, temperature, or moisture; flow blockage due to fouling (raw water, waste water only)	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There is no fiberglass piping, piping components, and tanks exposed to raw water (for components not covered by NRC GL 89-13), raw water (potable), treated water, or waste water in screened in portions of Auxiliary Systems.
3.3-1, 176	Fiberglass piping, piping components, tanks exposed to raw water environment (for components not covered by NRC GL 89-13), raw water (potable), treated water, waste water	Loss of material due to wear; flow blockage due to fouling (raw water, waste water only)	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There is no fiberglass piping, piping components, and tanks exposed to raw water environment (for components not covered by NRC GL 89-13), raw water (potable), treated water, or waste water in screened in portions of Auxiliary Systems.
3.3-1, 177	Fiberglass piping, piping components exposed to soil	Loss of material due to wear	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not Applicable. There is no fiberglass piping, piping components exposed to soil in screened in portions of Auxiliary Systems.
3.3-1, 178	Fiberglass piping and piping components exposed to concrete	None	None	No	Not Applicable. There are no fiberglass piping and piping components exposed to concrete in screened in portions of Auxiliary Systems.
3.3-1, 179	Masonry walls: structural fire barriers exposed to air	Cracking due to restraint shrinkage, creep, aggressive environment; loss of material (spalling, scaling) and cracking due to freeze-thaw	AMP XI.M26, "Fire Protection," and AMP XI.S5, "Masonry Walls"	No	Consistent with NUREG-2191. The Fire Protection program (B.2.1.15) and Masonry Walls program (B.2.1.32) will be used to manage cracking due to restraint shrinkage, creep, aggressive environment; loss of material (spalling, scaling) and cracking due to freeze-thaw of masonry walls: structural fire barriers exposed to air in Table 3.5.2-36: Structural Commodities (Hazard Barriers and Elastomers).

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 180	This Item Number is not used in NUREG-2192.				
3.3-1, 181	Titanium piping, piping components exposed to condensation	None	None	No	Not Applicable. There is no titanium piping, piping components exposed to condensation in screened in portions of Auxiliary Systems.
3.3-1, 182	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage reduced thermal insulation resistance of the aluminum, calcium silicate, caulking and lagging adhesive, cellular glass, fiberglass, foamed plastic, insulation cement and finishing cement, mineral fiber, plastic mastic jacketing, silicone, and stainless steel thermal insulation and thermal insulation jacketing exposed to air-indoor uncontrolled and air- outdoor as shown in Table 3.5.2-36: Structural Commodities (Thermal Insulation).
3.3-1, 183	This Item Number is not used in NUREG-2192.				
3.3-1, 184	PVC piping, piping components, tanks exposed to concrete	None	None	No	Not Applicable. There is no PVC piping, piping components, and tanks exposed to concrete in screened in portions of Auxiliary Systems.
3.3-1, 185	Aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Cracking due to SCC	AMP XI.M27, “Fire Water System”	No	Not Applicable. There are no aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water in screened in portions of Auxiliary Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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	Not Applicable. There are no aluminum tanks (within the scope of AMP XI.M29, “Outdoor and LargeAtmospheric Metallic Storage Tanks”) exposed to air, condensation, soil, concrete, raw water, or waste water in screened in portions of Auxiliary Systems. See Subsection 3.3.2.2.8.
3.3-1, 187	This Item Number is not used in NUREG-2192.				
3.3-1, 188	This Item Number is not used in NUREG-2192.				
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage cracking of aluminum piping, piping components, tanks exposed to air, condensation, raw water, raw water (potable), waste water. Impacted systems include, Fuel Oil, CO_2 Storage Fire Protection/Purge, Standby Liquid Control, Containment, Radiation Monitoring and Reactor Building Closed Cooling Water Systems. See Subsection 3.3.2.2.8.
3.3-1, 190	This Item Number is not used in NUREG-2192.				
3.3-1, 191	This Item Number is not used in NUREG-2192.				

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 192	Aluminum underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, “One-Time Inspection,” AMP XI.M41, “Buried and Underground Piping and Tanks,” or AMP XI.M42, “Internal Coatings/ Linings for In- Scope Piping, Piping Components, Heat Exchangers, and Tanks”	Yes	Not Applicable. There is no aluminum underground piping, piping components, and tanks in scoped in portions of Auxiliary Systems. See Subsection 3.3.2.2.8.
3.3-1, 193	Steel components exposed to treated water, raw water, raw water (potable), waste water	Long-term loss of material due to general corrosion	AMP XI.M32, “One-Time Inspection”	No	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) program will be used to manage long-term loss of material of the carbon steel, ductile iron, galvanized steel, and gray cast iron heat exchanger components, piping, piping components, and tanks exposed to raw water, sodium pentaborate solution, treated water, and waste water in the Emergency High Pressure Makeup, Emergency Equipment Cooling Water, Auxiliary Boiler, High Pressure Fire Protection (Diesel Driven Pump), Station Drainage, Standby Liquid Control, Reactor Water Cleanup, Radwaste, Spent Fuel Pool Cooling/Cleanup and Control Rod Drive Systems.
3.3-1, 194	PVC piping, piping components, and tanks exposed to soil	Loss of material due to wear	AMP XI.M41, “Buried and Underground Piping and Tanks”	No	Not Applicable. There is no PVC piping, piping components, and tanks exposed to soil in screened in portions of Auxiliary Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 195	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to raw water, treated water, raw water (potable)	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; flow blockage due to fouling (raw water only)	AMP XI.M27, “Fire Water System”	No	Not Applicable. There are no concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to raw water or treated water in screened in portions of Auxiliary Systems.
3.3-1, 196	HDPE piping, piping components exposed to raw water, treated water, raw water (potable)	Cracking, blistering; flow blockage due to fouling (raw water only)	AMP XI.M27, “Fire Water System”	No	Not Applicable. There are no HDPE piping, piping components exposed to raw water or treated water in screened in portions of Auxiliary Systems.
3.3-1, 197	Metallic fire water system piping, piping components, heat exchanger, heat exchanger components (any material) with only a Pressure 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. There is no metallic fire water system piping, piping components, heat exchanger, heat exchanger components (any material) with only a Pressure Boundary (spatial) or structural integrity (attached) intended function exposed to any external environment except soil, concrete in screened in portions of Auxiliary Systems that has not been addressed.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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 Pressure Boundary (spatial) or structural integrity (attached) intended function	Loss of material dueto 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. There is no metallic fire water system piping, piping components, heat exchanger, heat exchanger components (any material) with only a Pressure Boundary (spatial) or structural integrity (attached) intended function in screened in portions of Auxiliary Systems that has not been addressed.
3.3-1, 199	Cranes: steel structural bolting exposed to air	Loss of preload due to self-loosening; loss of material due to general corrosion; cracking	AMP XI.M23, “Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems”	No	Consistent with NUREG-2191. The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program (B.2.1.13) will be used to manage cracking, loss of material, and loss of preload of the carbon and low alloy steel structural bolting and high strength low alloy steel structural bolting with yield strength of 150 ksi or greater exposed to air-indoor uncontrolled the Fuel Handling and Storage and Cranes and Hoists Systems.
3.3-1, 200	This Item Number is not used in NUREG-2192.				
3.3-1, 201	This Item Number is not used in NUREG-2192.				
3.3-1, 202	Stainless steel piping, piping components exposed to concrete	None	None	Yes	Consistent with NUREG-2191. Stainless steel piping, piping components exposed to concrete do not have an aging effect nor do they have an Aging Management Program assigned. This Item Number is applicable to Spent Fuel Pool Cooling/Cleanup. See Subsection 3.3.2.2.9.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) and Water Chemistry program (B.2.1.2) will be used to manage loss of material of the carbon or low alloy steel with stainless steel cladding, and stainless steel heat exchanger components, piping, piping components, and tanks exposed to sodium pentaborate solution and treated water in the Emergency High Pressure Makeup, Radiation Monitoring, Residual Heat Removal Service Water, Raw Cooling Water, Sampling and Water Quality, Standby Liquid Control, Containment, Reactor Water Cleanup, Radwaste, Spent Fuel Pool Cooling/Cleanup, and Control Rod Drive Systems.
3.3-1, 204	This Item Number is not used in NUREG-2192.				
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) program will be used to manage Cracking due to SCC for insulated stainless steel piping, piping components, tanks exposed to air, condensation in Sampling and Water Quality System. See Subsection 3.3.2.2.3.
3.3-1, 206	This Item Number is not used in NUREG-2192.				

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 207	Stainless steel, copper alloy, titanium heat exchanger tubes exposed to raw water (forcomponents 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	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) will be used to manage copper alloy heat exchanger tubes exposed to raw water (for components not covered by NRC GL 89-13) in screened in portions of Residual Heat Removal Service Water System.
3.3-1, 208	Concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to raw water (for components not covered by NRC GL 89-13)	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement (reinforced concrete only); loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no concrete, concrete cylinder piping, reinforced concrete, asbestos cement, cementitious piping, piping components exposed to raw water (for components not covered by NRC GL 89-13) in screened in portions of Auxiliary Systems.
3.3-1, 209	This Item Number is not used in NUREG-2192.				
3.3-1, 210	HDPE piping, piping components exposed to raw water (for components not covered by NRC GL 89-13)	Cracking, blistering; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There is no HDPE piping, piping components exposed to raw water (for components not covered by NRC GL 89-13) in screened in portions of Auxiliary Systems.
3.3-1, 211	This Item Number is not used in NUREG-2192.				
3.3-1, 212	This Item Number is not used in NUREG-2192.				
3.3-1, 213	This Item Number is not used in NUREG-2192.				

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191. Loss of material due to selective leaching for copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil will be managed by Selective Leaching program (B.2.1.21) in the High Pressure Fire Protection (Diesel Driven Pump) System.
3.3-1, 215	Aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Loss of material due to pitting, crevice corrosion	AMP XI.M27, "Fire Water System"	No	Not Applicable. There are no aluminum fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), ortreated water in screened in portions of Auxiliary Systems.
3.3-1, 216	Stainless steel fire water storage tanks exposed to air, condensation, soil, concrete	Cracking due to SCC	AMP XI.M27, "Fire Water System"	No	Not Applicable. There are no stainless steel fire water storage tanks exposed to air, condensation, soil, or concrete in screened in portions of Auxiliary Systems.
3.3-1, 217	This Item Number is not used in NUREG-2192.				
3.3-1, 218	Stainless steel fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water	Loss of material due to pitting, crevice corrosion, MIC (water and soil environment only)	AMP XI.M27, "Fire Water System"	No	Not Applicable. There are no stainless steel fire water storage tanks exposed to air, condensation, soil, concrete, raw water, raw water (potable), treated water in screened in portions of Auxiliary Systems.
3.3-1, 219	Stainless steel piping, piping components exposed to steam	Cracking due to SCC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. Cracking due to SCC in stainless steel piping, piping components exposed to steam will be managed by the Water Chemistry program (B.2.1.2) and the One-Time Inspection program (B.2.1.20) for Auxiliary Boiler System.
3.3-1, 220	This Item Number is not used in NUREG-2192.				

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 221	This Item Number is not used in NUREG-2192.				
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	Not Applicable. There is no stainless steel, nickel alloy tanks exposed to air, condensation (internal/external) within the screened in portions of Auxiliary Systems. See Subsection 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	Not Applicable. There is no aluminum underground piping, piping components, and tanks in screened in portions of Auxiliary Systems. See Subsection 3.3.2.2.10.
3.3-1, 224	This Item Number is not used in NUREG-2192.				
3.3-1, 225	This Item Number is not used in NUREG-2192.				
3.3-1, 226	Aluminum tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”	No	Not Applicable. There are no aluminum tanks (within the scope of AMP XI.M29, “Outdoor and LargeAtmospheric Metallic Storage Tanks”) exposed to soil or concrete in screened in portions of Auxiliary Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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	Not Applicable. There are no aluminum tanks (within the scope of AMP XI.M29, “Outdoor and LargeAtmospheric Metallic Storage Tanks”) exposed to air or condensation in screened in portions of Auxiliary Systems. See Subsection 3.3.2.2.10.
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	Not Applicable. There are no stainless steel, nickel alloy tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to air or condensation in screened in portions of Auxiliary Systems. See Subsection 3.3.2.2.4.
3.3-1, 229	Stainless steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”	No	Not Applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to soil or concrete in screened in portions of Auxiliary Systems.
3.3-1, 230	Stainless steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to soil, concrete	Cracking due to SCC	AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”	No	Not Applicable. There are no stainless steel tanks (withinthe scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to soil or concrete in screened in portions of Auxiliary Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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	Not Applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to air or condensation in screened in portions of Auxiliary Systems. See Subsection 3.3.2.2.3.
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage loss of material of the insulated stainless steel, nickel alloy piping, piping components, tanks exposed to air and condensation. Impacted systems include Standby Liquid Control, Emergency Equipment Cooling Water, Reactor Water Cleanup, Containment Inerting, Spent Fuel Pool Cooling/ Cleanup and Control Rod Drive Systems. See Subsection 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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage cracking due to SCC in insulated aluminum piping, piping components, tanks exposed to air, condensation for in- scope piping, piping components, heat exchangers, and tanks for High Pressure Fire Protection (Diesel Driven Pump) System. See Subsection 3.3.2.2.8.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage loss of material in aluminum piping, piping components, tanks exposed to air and condensation. Impacted systems include in the Fuel Oil, Residual Heat Removal Service Water, High Pressure Fire Protection (Diesel Driven Pump), Air Conditioning, Control Air, Containment, Containment Inerting, Spent Fuel Pool Cooling/Cleanup, Control Rod Drive, and Diesel Generator Starting Air Systems. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) will be used to manage loss of material in aluminum piping, piping components, tanks exposed to air and condensation in the Radiation Monitoring System. See Subsection 3.3.2.2.10.
3.3-1, 235	Metallic piping, piping components exposed to air-dry (internal)	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M24, “Compressed Air Monitoring”	No	Consistent with NUREG-2191. The Compressed Air Monitoring program (B.2.1.14) will be used to manage loss of material of the aluminum alloy, carbon steel, copper alloy, and stainless steel piping, piping components exposed to air-dry in the Control Air, Demineralizer Backwash Air, Main Steam, Reactor Building Closed Cooling Water and Diesel Generator Starting Air Systems.
3.3-1, 236	Titanium heat exchanger tubes exposed to treated water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M2, “Water Chemistry,” and AMP XI.M32, “One-Time Inspection”	No	Not Applicable. There are no titanium heat exchanger tubes exposed to treated water in screened in portions of Auxiliary Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 237	Titanium (ASTM Grades1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to treated water	None	None	No	.Not Applicable. There are no titanium (ASTM Grades1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to treated water in screened in portions of Auxiliary Systems.
3.3-1, 238	Titanium heat exchanger tubes exposed to closed-cycle cooling water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M21A, “Closed Treated Water Systems”	No	Not Applicable. There are no titanium heat exchanger tubes exposed to closed-cycle cooling water in screened in portions of Auxiliary Systems.
3.3-1, 239	Titanium (ASTM Grades1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to closed-cycle cooling water	None	None	No	Not Applicable. There is no 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 screened in portions of Auxiliary Systems.
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	Not Applicable. There are no aluminum heat exchanger components exposed to waste water in screened in portions of Auxiliary Systems. See Subsection 3.3.2.2.10.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 241	Stainless steel, nickel alloy heat exchanger components exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M32, “One-Time Inspection,” AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,” or AMP XI.M42, “Internal Coatings/ Linings for In- Scope Piping, Piping Components, Heat Exchangers, and Tanks”	Yes	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage loss of material of stainless steel, nickel alloy heat exchanger components exposed to air and condensation. Impacted systems include, Sampling and Water Quality, Auxiliary Decay Heat Removal, Containment Inerting and Containment Atmosphere Dilution Systems. See Subsection 3.3.2.2.4.
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage loss of material in aluminum heat exchanger components exposed to air and condensation. Impacted systems include Air Conditioning, Emergency Equipment Cooling Water and Standby Diesel Generator Systems. See Subsection 3.3.2.2.10.
3.3-1, 243	This Item Number is not used in NUREG-2192.				
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) and Water Chemistry program (B.2.1.2) will be used to manage cracking of cast austenitic stainless steel and stainless steel piping, piping components exposed to treated water > 140 F and treated water > 482 F in the Reactor Water Cleanup System.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Not Applicable. There are no Insulated aluminum piping, piping components, tanks exposed to air, condensation in screened in portions of Auxiliary Systems. See Subsection 3.3.2.2.10.
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage aging for stainless steel underground piping, piping components, and tanks in screened in portions of Spent Fuel Pool Cooling/Cleanup System. See Subsection 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	Not Applicable. There are no aluminum piping, piping components, and tanks exposed to raw water and waste water in screened in portions of Auxiliary Systems. See Subsection 3.3.2.2.10.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 248	Aluminum piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not Applicable. There are no aluminum piping, piping components, and tanks exposed to air with borated water leakage in screened in portions of Auxiliary Systems.
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. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) will be used to manage loss of material of the carbon steel heat exchanger components exposed to condensation in the Reactor Building Closed Cooling Water Systems.
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) program will be used to manage loss of material due to general, pitting, crevice corrosion, MIC in piping, piping components exposed to lubricating oil (waste oil) in the Radwaste System.
3.3-1, 251	This Item Number is not used in NUREG-2192.				
3.3-1, 252	Aluminum piping, piping components exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M41, “Buried and Underground Piping and Tanks”	No	Not Applicable. There is no aluminum piping, piping components exposed to soil or concrete in screened in portions of Auxiliary Systems.
3.3-1, 253	PVC piping, piping components exposed to raw water, raw water (potable), treated water, waste water	Loss of material due to wear; flow blockage due to fouling (raw water only)	AMP XI.M20, “Open-Cycle Cooling Water System,” AMP XI.M27, “Fire Water System,” or AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Not Applicable. There is no PVC piping, piping components exposed to raw water, raw water (potable), treated water, waste water in screened in portions of Auxiliary Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	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	Not applicable. There are no aluminum heat exchanger components exposed to air, condensation in screened in portions of Auxiliary Systems. See Subsection 3.3.2.2.8.
3.3-1, 255	Any material fire damper assemblies exposed to air	Loss of material due to general, pitting, crevice corrosion; cracking due to SCC; hardening, loss of strength, shrinkage due to elastomer degradation	AMP XI.M26, “Fire Protection”	No	Consistent with NUREG-2191. The Fire Protection program (B.2.1.15) will be used to manage loss of material of the galvanized steel fire barriers exposed to air-indoor uncontrolled in the Normal Ventilation, Air Conditioning, CO_2 Storage Fire Protection/Purge, and Containment Systems.
3.3-1, 256	This Item Number is not used in NUREG-2192.				
3.3-1, 257	Steel, stainless steel, copper alloy heat exchanger tubes exposed to lubricating oil	Reduction of heat transfer due to fouling	AMP XI.M39, “Lubricating Oil Analysis,” and AMP XI.M32, “One-Time Inspection”	No	Consistent with NUREG-2191. The Lubricating Oil Analysis program (B.2.1.25) and One-Time Inspection program (B.2.1.20) program will be used to manage reduction of heat transfer of the copper alloy and stainless heat exchanger tubes exposed to lubricating oil in the Air Conditioning, Standby Diesel Generators, Condenser Circulating Water, and Control Rod Drive Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 258	Metallic, elastomer, fiberglass, HDPE piping, piping components exposed to waste water	Flow blockage due to fouling	AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Not Applicable. There are no metallic, elastomer, fiberglass, HDPE piping, piping components exposed to waste water with aflow rate or heat transfer function in screened in portions of Auxiliary Systems.
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	Consistent with NUREG-2191. The Open-Cycle Cooling Water System program (B.2.1.11) program will be used to manage flow blockage due to fouling of aluminum piping, piping components exposed to raw water in screened in portions of the Radiation Monitoring System.
3.3-1, 260	Metallic HVAC closure bolting exposed to air, condensation	Loss of material due to general (where applicable), pitting, crevice corrosion; cracking due to SCC, loss of preload	AMP XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	Consistent with NUREG-2191 The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage loss of material and loss of preload of the carbon and low alloy steel HVAC closure bolting exposed to air-indoor uncontrolled in the Emergency High Pressure Makeup, Normal Ventilation, and Air Conditioning Systems.
3.3-1, 261	Titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to closed-cycle cooling water, raw water	Cracking due to SCC	AMP XI.M20, “Open-Cycle Cooling Water System,” or AMP XI.M21A, “Closed Treated Water Systems”	No	Not Applicable. There are no titanium (ASTM Grades 3, 4,or 5) heat exchanger tubes exposed to closed-cycle cooling water or raw water in screened in portions of Auxiliary Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 262	Titanium piping, piping components, heat exchanger components exposed to closed-cycle cooling water, treated water	Cracking due to SCC	AMP XI.M20, “Open-Cycle Cooling Water System,” or AMP XI.M21A, “Closed Treated Water Systems,” or AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Not Applicable. There is no titanium piping, piping components, and heat exchanger components exposed to closed-cycle cooling water in screened in portions of Auxiliary Systems.
3.3-1, 263	Polymeric piping, piping components, ducting, ducting components, seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, soil	Hardening or loss of strength due to polymeric degradation; loss of material due to peeling, delamination, wear; cracking or blistering due to exposure to ultraviolet light, ozone, radiation,or chemical attack; flow blockage due to fouling	AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” or AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Consistent with NUREG-2191 the External Surfaces Monitoring of Mechanical Components program (B.2.1.23), or Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) will be used to manage 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 in the Radiation Monitoring, Residual Heat Removal Service Water, Raw Cooling Water, Air Conditioning, Sampling and Water Quality, and Hypochlorite Systems.
3.3-1, 264	This Item Number is reserved and not currently used in NUREG-2192.				
3.3-1, 265	Steel heat exchanger tubes exposed to fuel oil	Reduction of heat transfer due to fouling	XI.M30, “Fuel Oil Chemistry,” and XI.M32, “One-Time Inspection”	No	Not Applicable. There are no steel heat exchanger tubes exposed to fuel oil in screened in portions of Auxiliary Systems.
3.3-1, 266	Steel heat exchanger tubes exposed to fuel oil	Reduction of heat transfer due to fouling	XI.M30, “Fuel Oil Chemistry”	No	Not Applicable. There are no steel heat exchanger tubes exposed to fuel oil in screened in portions of Auxiliary Systems.

Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3-1, 267	Subliming compound fireproofing/fire barriers (Thermo- lag®, Darmatt™, 3M™ Interam™, and other similar materials) exposed to air	Loss of material due to abrasion, flaking, vibration; cracking/ delamination due to chemical reaction, settlement; change in material properties due to gamma irradiation exposure; separation	AMP XI.M26, “Fire Protection”	No	Consistent with NUREG-2191. There are no subliming compound fireproofing/fire barriers (Thermo- lag®, Darmatt™, 3M™ Interam™, and other similar materials) exposed to air addressed in screened in portions of Auxiliary Systems. However, this item is used in Table 3.5.2-36: Structural Commodities (Hazard Barriers and Elastomers).
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 due to abrasion, exfoliation, elevated temperature, flaking, spalling; cracking/delamination due to chemical reaction, elevated temperature, settlement, vibration; change in material properties due to elevated temperature, gamma irradiation exposure; separation	AMP XI.M26, “Fire Protection”	No	Consistent with NUREG-2191. There are no cementitious coating fireproofing/fire barriers (Pyrocrete, BIO™ K-10 Mortar, Cafecote, and other similar materials) exposed to air addressed in screened in portions of Auxiliary Systems. However, this item is used in Table 3.5.2-36: Structural Commodities (Hazard Barriers and Elastomers).
3.3-1, 269	Silicate fireproofing/fire barriers (Marinite®, Kaowool™, Cerafiber®, Cera® blanket, or other similar materials) exposed to air	Loss of material due to abrasion, flaking; cracking/delamination due to settlement; change in material properties due to gamma irradiation exposure; separation	AMP XI.M26, “Fire Protection”	No	Consistent with NUREG-2191. There are no silicate fireproofing/fire barriers (Marinite®, Kaowool™, Cerafiber®, Cera® blanket, or other similar materials) exposed to air addressed in screened in portions of Auxiliary Systems. However, this item is used in Table 3.5.2-36: Structural Commodities (Hazard Barriers and Elastomers).

Table 3.3.2-1, Emergency High Pressure Makeup System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Treated water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	VII.C2.A-439	3.3-1, 193	A
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Metallic	Air, condensation	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Closure bolting	Mechanical Closure	Steel	treated 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)	Bolting Integrity (B.2.1.10)	VII.I.A-423	3.3-1, 142	A, 1
Closure bolting HVAC	Mechanical Closure	Metallic	Air, condensation	Loss of material due to general (where applicable), pitting, crevice corrosion; cracking due to SCC, loss of preload	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.F2.A-794	3.3-1, 260	A
Ducting, ducting components,	Pressure Boundary	Galvanized Steel	Air - indoor controlled	None	None	V.F.EP-14	3.2-1, 059	A

Table 3.3.2-1, Emergency High Pressure Makeup System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Ducting, ducting components, (internal surfaces)	Pressure Boundary	Galvanized Steel	Condensation	Loss of material due to general, pitting, crevice corrosion, MIC (for drip pans and drain lines only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F2.A-08	3.3-1, 090	A
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A
Insulated piping, piping components, tanks	Pressure Boundary	Steel	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)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A
Piping, piping components	Pressure Boundary	Steel	Air	Cumulative fatigue damage due to fatigue	Section 4.3, "Metal Fatigue"	VII.E3.A-34	3.3-1, 002	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.C1.AP-209a	3.3-1, 004	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.C2.AP-221a	3.3-1, 006	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-106	3.3-1, 021	A
Piping, piping components	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-24	3.3-1, 080	A
Piping, piping components	Pressure Boundary	Steel	Lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.C1.AP-127	3.3-1, 097	A

Table 3.3.2-1, Emergency High Pressure Makeup System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Treated water	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	VII.E3.A-408	3.3-1, 126	A
Piping, piping components	Pressure Boundary	Stainless steel	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-110	3.3-1, 203	A

Table 3.3.2-1 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. This GALL-SLR item reflects consideration of leakage from a flanged connection. However, this system does not contain any submerged closure bolting.

Table 3.3.2-2, Auxiliary Boiler System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Treated water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	VII.E3.A-439	3.3-1, 193	A
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A
Insulated piping, piping components, tanks	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Air, condensation	Loss of material due to general (steel only), pitting, crevice corrosion; cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A
Insulated piping, piping components, tanks	Pressure Boundary	Steel	Air, condensation	Loss of material due to general (steel only), pitting, crevice corrosion; cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A
Piping, piping components	Pressure Boundary	Steel	Air	Cumulative fatigue damage due to fatigue	Section 4.3, “Metal Fatigue”	VII.E3.A-34	3.3-1, 002	A

Table 3.3.2-2, Auxiliary Boiler System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.C1.AP-209a	3.3-1, 004	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.F3.AP-221a	3.3-1, 006	A
Piping, piping components	Pressure Boundary	Copper alloy	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.A4.AP-140	3.3-1, 022	A
Piping, piping components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.C2.AP-32	3.3-1, 072	A
Piping, piping components	Pressure Boundary	Copper alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A
Piping, piping components	Pressure Boundary	Steel	Steam	Loss of material due to general (steel only), pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.F3.A-566	3.3-1, 169	A
Piping, piping components	Pressure Boundary	Stainless steel	Steam	Cracking due to SCC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.F3.A-748	3.3-1, 219	A
Piping, piping components	Pressure Boundary	Steel	Steam	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.B2.S-15	3.4-1, 005	A

Table 3.3.2-2 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-3, Fuel Oil System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
External surfaces	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.H1.AP-209a	3.3-1, 004	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.H1.AP-221a	3.3-1, 006	A
Piping, piping components	Pressure Boundary	Copper alloy	Fuel oil	Loss of material due to pitting, crevice corrosion, MIC	Fuel Oil Chemistry (B.2.1.18) and One-Time Inspection (B.2.1.20)	VII.H1.AP-132	3.3-1, 069	B
Piping, piping components, tanks	Pressure Boundary	Steel	Fuel oil	Loss of material due to general, pitting, crevice corrosion, MIC	Fuel Oil Chemistry (B.2.1.18)	VII.H1.AP-105a	3.3-1, 070	B

Table 3.3.2-3, Fuel Oil System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Aluminum	Fuel oil	Loss of material due to pitting, crevice corrosion, MIC	Fuel Oil Chemistry (B.2.1.18) and One-Time Inspection (B.2.1.20)	VII.H1.AP-129	3.3-1, 071	B
Piping, piping components	Pressure Boundary	Stainless steel	Fuel oil	Loss of material due to pitting, crevice corrosion, MIC	Fuel Oil Chemistry (B.2.1.18) and One-Time Inspection (B.2.1.20)	VII.H1.AP-136	3.3-1, 071	B, 1
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Elastomer	Air, condensation	Hardening or loss of strength due to elastomer degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3-1, 076	A
Piping, piping components	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-24	3.3-1, 080	A
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Elastomer	Air	Loss of material due to wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-113	3.3-1, 082	A
Piping, piping components, seals	Pressure Boundary	Elastomer	Fuel oil	Hardening or loss of strength due to elastomer degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H1.A-660	3.3-1, 085	A
Piping, piping components	Pressure Boundary	Steel	Concrete	None	None	VII.J.AP-282	3.3-1, 112	A
Piping, piping components	Pressure Boundary	Copper alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A
Tanks	Pressure Boundary	Steel	Concrete	None	None	VII.J.AP-282	3.3-1, 112	C

Table 3.3.2-3, Fuel Oil System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Piping, piping components, tanks	Pressure Boundary	Aluminum	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.H1.A-451a	3.3-1, 189	A
Piping, piping components, tanks	Pressure Boundary	Aluminum	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.H1.A-763a	3.3-1, 234	A

Table 3.3.2-3 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. Stainless steel components include piping, tubing, and valves that support diesel engine operation. The stainless steel grouping includes nickel alloys. Loss of material due to MIC is identified as an aging effect.

Table 3.3.2-4, Residual Heat Removal Service Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Stainless steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Stainless steel	Air - outdoor	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Closure bolting	Mechanical Closure	Stainless steel	Raw 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)	Bolting Integrity (B.2.1.10)	VII.I.A-423	3.3-1, 142	A
Closure bolting	Mechanical Closure	Steel	Raw 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)	Bolting Integrity (B.2.1.10)	VII.I.A-423	3.3-1, 142	A

Table 3.3.2-4, Residual Heat Removal Service Water System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat exchanger components	Pressure Boundary	Steel	Raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3-1, 038	A
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Stainless steel	Raw water	Cracking due to SCC (titanium only), reduction of heat transfer due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-187	3.3-1, 042	A
Heat exchanger tubes (for components not covered by NRC GL 89-13)	Pressure Boundary, Heat Transfer	Stainless steel	Raw water	Cracking due to SCC (titanium only), reduction of heat transfer due to fouling	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-736	3.3-1, 207	A
Heat exchanger tubes	Pressure Boundary,, Heat Transfer	Stainless steel	Raw water	Reduction of heat transfer due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VIII.E.S-28	3.4-1, 022	A
Insulated piping, piping components, tanks	Pressure Boundary	Steel	Air, condensation	Loss of material due to general (steel only), pitting, crevice corrosion; cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A
Piping, piping components	Pressure Boundary	Steel	Air	Cumulative fatigue damage due to fatigue	Section 4.3, “Metal Fatigue”	VII.E3.A-34	3.3-1, 002	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.C1.AP-209a	3.3-1, 004	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-106	3.3-1, 021	A

Table 3.3.2-4, Residual Heat Removal Service Water System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Aluminum	Treated water	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.C2.AP-130	3.3-1, 025	A
Piping, piping components	Pressure Boundary	Copper alloy	Raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3-1, 034	A
Piping, piping components	Pressure Boundary	Steel	Raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3-1, 037	A
Piping, piping components	Pressure Boundary	Stainless steel	Raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3-1, 040	A
Piping, piping components	Pressure Boundary	Gray cast iron, ductile iron	Raw water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3-1, 072	A
Piping, piping components	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-24	3.3-1, 080	A
Piping, piping components	Pressure Boundary	Steel	Lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.C1.AP-127	3.3-1, 097	A
Piping, piping components	Pressure Boundary	Steel	Soil	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-198	3.3-1, 109	B
Piping, piping components	Pressure Boundary	Steel	Concrete	None	None	VII.J.AP-282	3.3-1, 112	A

Table 3.3.2-4, Residual Heat Removal Service Water System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Copper alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A
Piping, piping components, heat exchangers with internal coatings/linings	Pressure Boundary, Heat Transfer	Steelwith internal coatings/linings	Raw water	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, physical damage; loss of material or cracking for cementitious coatings/linings	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.G.A-416	3.3-1, 138	A
Piping, piping components	Pressure Boundary	Stainless steel	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-110	3.3-1, 203	A
Piping, piping components, tanks	Pressure Boundary	Aluminum	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.H1.A-763a	3.3-1, 234	A
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Polymeric	Treated water	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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-797b	3.3-1, 263	A

Table 3.3.2-4, Residual Heat Removal Service Water System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Polymeric	Air	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	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3-1, 263	A

Table 3.3.2-4 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-5, Raw Cooling Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Steel	Raw water	Reduction of heat transfer due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	V.D2.E-23	3.2-1, 027	A
Heat exchanger components	Pressure Boundary	Copper alloy	Raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3-1, 038	A
Heat exchanger components	Pressure Boundary	Steel	Raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3-1, 038	A
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Stainless steel	Raw water	Cracking due to SCC (titanium only), reduction of heat transfer due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-187	3.3-1, 042	A
Heat exchanger components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Raw water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.C1.A-66	3.3-1, 072	A

Table 3.3.2-5, Raw Cooling Water System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Insulated piping, piping components, tanks	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Air, condensation	Loss of material due to general (steel only), pitting, crevice corrosion; cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.C1.AP-209a	3.3-1, 004	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.C1.AP-221a	3.3-1, 006	A
Piping, piping components	Pressure Boundary	Copper alloy	Raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3-1, 034	A
Piping, piping components	Pressure Boundary	Steel	Raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3-1, 037	A
Piping, piping components	Pressure Boundary	Stainless steel	Raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3-1, 040	A
Piping, piping components	Pressure Boundary	Gray cast iron, ductile iron	Raw water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3-1, 072	A
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Elastomer	Air, condensation	Hardening or loss of strength due to elastomer degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3-1, 076	A

Table 3.3.2-5, Raw Cooling Water System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-24	3.3-1, 080	A
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Elastomer	Air	Loss of material due to wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-113	3.3-1, 082	A
Piping, piping components, seals	Pressure Boundary	Elastomer	Raw water	Loss of material due to wear; flow blockage due to fouling (raw water, waste water only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F1.AP-103	3.3-1, 096	A
Piping, piping components	Pressure Boundary	Steel	Lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.C1.AP-127	3.3-1, 097	A
Piping, piping components	Pressure Boundary	Stainless steel	Raw water	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	VII.C1.A-409	3.3-1, 126	A
Piping, piping components	Pressure Boundary	Steel	Raw water	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	VII.C1.A-409	3.3-1, 126	A
Piping, piping components	Pressure Boundary	Steel	Air, condensation	Loss of material due to general (steel only), pitting, crevice corrosion; cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.C1.A-409	3.3-1, 126	A
Piping, piping components, heat exchanger components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Raw water	Cracking due to SCC	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-473b	3.3-1, 160	A

Table 3.3.2-5, Raw Cooling Water System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless steel	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-110	3.3-1, 203	A
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Polymeric	Air, condensation	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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-797b	3.3-1, 263	A
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Polymeric	Air, condensation	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	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3-1, 263	A

Table 3.3.2-5 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-6, Raw Service Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Copper alloy	Raw water	Cracking due to SCC (titanium only), reduction of heat transfer due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-187	3.3-1, 042	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.C1.AP-209a	3.3-1, 004	A
Piping, piping components	Pressure Boundary	Copper alloy	Raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3-1, 034	A
Piping, piping components	Pressure Boundary	Steel	Raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3-1, 037	A
Piping, piping components	Pressure Boundary	Stainless steel	Raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3-1, 040	A
Piping, piping components	Pressure Boundary	Gray cast iron, ductile iron	Soil	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.C1.A-02	3.3-1, 072	A
Piping, piping components	Pressure Boundary	Gray cast iron, ductile iron	Raw water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3-1, 072	A

Table 3.3.2-6, Raw Service Water System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-24	3.3-1, 080	A
Piping, piping components	Pressure Boundary	Copper Alloy	Soil	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-174	3.3-1, 108	B
Piping, piping components	Pressure Boundary	Copper alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A
Piping, piping components, heat exchanger components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Raw water	Cracking due to SCC	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-473b	3.3-1, 160	A

Table 3.3.2-6 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-7, High Pressure Fire Protection (Diesel Driven Pump) System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Raw water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	VII.G.A-532	3.3-1, 193	A
Closure Bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure Bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure Bolting	Mechanical Closure	Steel	Air	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Closure bolting	Mechanical Closure	Steel	Raw 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)	Bolting Integrity (B.2.1.10)	VII.I.A-423	3.3-1, 142	A
Fire Hydrant	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion; flow blockage due to fouling (raw water, raw water (potable) only)	Fire Water System (B.2.1.16)	VII.G.AP-149	3.3-1, 063	A
Fire Hydrant	Pressure Boundary	Gray cast iron	Raw water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.G.A-51	3.3-1, 072	A

Table 3.3.2-7, High Pressure Fire Protection (Diesel Driven Pump) System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Fire water storage tanks	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC (raw water, raw water (potable), treated water, soil only)	Fire Water System (B.2.1.16)	VII.G.A-412	3.3-1, 136	A
Halon/carbon dioxide fire suppression system piping, piping components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Fire Protection (B.2.1.15)	VII.G.AP-150	3.3-1, 058	A
Heat exchanger components	Pressure Boundary	Copper alloy	Raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3-1, 038	A
Heat exchanger components	Pressure Boundary	Steel	Closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3-1, 046	A
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Copper Alloy	Closed-cycle cooling water	Reduction of heat transfer due to fouling	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-205	3.3-1, 050	A
Heat exchanger components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Raw water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.C1.A-66	3.3-1, 072	A
Heat exchanger components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.F1.AP-65	3.3-1, 072	A
Heat exchanger components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3-1, 080	A

Table 3.3.2-7, High Pressure Fire Protection (Diesel Driven Pump) System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Insulated piping, piping components, tanks	Pressure Boundary	Steel	Air, condensation	Loss of material due to general (steel only), pitting, crevice corrosion; cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A
Insulated piping, piping components, tanks	Pressure Boundary	Aluminum	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.I.A-762b	3.3-1, 233	A
Piping, piping components	Pressure Boundary	Steel	Any	Cumulative fatigue damage due to fatigue	Section 4.3, “Metal Fatigue”	VII.E3.A-34	3.3-1, 002	A
Piping, piping components	Pressure Boundary	Stainless steel	Any	Cumulative fatigue damage due to fatigue	Section 4.3, “Metal Fatigue”	VII.E3.A-62	3.3-1, 002	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.G.AP-209a	3.3-1, 004	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.G.AP-221a	3.3-1, 006	A
Piping, piping components	Pressure Boundary	Steel	Raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling (raw water, raw water (potable) only)	Fire Water System (B.2.1.16)	VII.G.A-33	3.3-1, 064	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling (raw water, raw water (potable) only)	Fire Water System (B.2.1.16)	VII.G.A-33	3.3-1, 064	A

Table 3.3.2-7, High Pressure Fire Protection (Diesel Driven Pump) System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Copper alloy	Raw water	Loss of material due to general (raw water, raw water (potable) only), pitting, crevice corrosion, MIC; flow blockage due to fouling (raw water only)	Fire Water System (B.2.1.16)	VII.G.AP-197	3.3-1, 064	A
Piping, piping components	Pressure Boundary	Aluminum	Treated water	Loss of material due to pitting, crevice corrosion; flow blockage due to fouling (raw water only)	Fire Water System (B.2.1.16)	VII.G.AP-180	3.3-1, 065	A
Piping, piping components	Pressure Boundary	Stainless steel	Raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling (raw water only)	Fire Water System (B.2.1.16)	VII.G.A-55	3.3-1, 066	A
Piping, piping components, tanks	Pressure Boundary	Steel	Fuel oil	Loss of material due to general, pitting, crevice corrosion, MIC	Fuel Oil Chemistry (B.2.1.18)	VII.G.AP-234a	3.3-1, 070	B
Piping, piping components	Pressure Boundary	Gray cast iron, ductile iron	Soil	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.C1.A-02	3.3-1, 072	A
Piping, piping components	Pressure Boundary	Gray cast iron	Raw water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3-1, 072	A
Piping, piping components	Pressure Boundary	Gray cast iron, ductile iron	Soil	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.G.A-02	3.3-1, 072	A
Piping, piping components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Raw water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.G.A-47	3.3-1, 072	A
Piping, piping components	Pressure Boundary	Gray cast iron	Raw water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.G.A-51	3.3-1, 072	A

Table 3.3.2-7, High Pressure Fire Protection (Diesel Driven Pump) System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Gray cast iron	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.G.A-51	3.3-1, 072	A
Piping, piping components	Pressure Boundary	Gray cast iron	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.G.AP-31	3.3-1, 072	A
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Elastomer	Air, condensation	Hardening or loss of strength due to elastomer degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3-1, 076	A
Piping, piping components	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-24	3.3-1, 080	A
Piping, piping components, seals	Pressure Boundary	Elastomer	Treated water	Hardening or loss of strength due to elastomer degradation; flow blockage due to fouling (raw water only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.G.AP-75	3.3-1, 085	A
Piping, piping components, seals	Pressure Boundary	Elastomer	Fuel oil	Hardening or loss of strength due to elastomer degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H1.A-660	3.3-1, 085	A
Piping, piping components, seals	Pressure Boundary	Elastomer	Raw water	Loss of material due to wear; flow blockage due to fouling (raw water only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.G.AP-76	3.3-1, 096	A
Piping, piping components	Pressure Boundary	Steel	Lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.C1.AP-127	3.3-1, 097	A

Table 3.3.2-7, High Pressure Fire Protection (Diesel Driven Pump) System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Piping, piping components	Pressure Boundary	Copper Alloy	Soil	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-174	3.3-1, 108	B
Piping, piping components	Pressure Boundary	Steel	Concrete	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-198	3.3-1, 109	B
Piping, piping components	Pressure Boundary	Steel	Soil	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-198	3.3-1, 109	B
Piping, piping components	Pressure Boundary	Steel	Concrete	None	None	VII.J.AP-282	3.3-1, 112	A
Piping, piping components	Pressure Boundary	Copper alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A
Piping elements	Pressure Boundary	Glass	Air	None	None	VII.J.AP-48	3.3-1, 117	A
Piping, piping components	Pressure Boundary	Copper alloy	Air, condensation	Flow blockage due to fouling	Fire Water System (B.2.1.16)	VII.G.A-404	3.3-1, 131	A
Piping, piping components	Pressure Boundary	Steel	Air, condensation	Flow blockage due to fouling	Fire Water System (B.2.1.16)	VII.G.A-404	3.3-1, 131	A
Piping, piping components, heat exchangers with internal coatings/linings	Pressure Boundary	Steel	Raw Water	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, physical damage; loss of material or cracking for cementitious coatings/linings	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.G.A-416	3.3-1, 138	A

Table 3.3.2-7, High Pressure Fire Protection (Diesel Driven Pump) System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Piping, piping components, heat exchangers with internal coatings/linings	Pressure Boundary	Steel	Raw Water	Loss of material due to general, pitting, crevice corrosion, MIC	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.G.A-414	3.3-1, 139	A
Piping components with internal coatings/linings	Pressure Boundary	Gray cast iron	Raw Water	Loss of material due to selective leaching	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.G.A-415	3.3-1, 140	A
Piping components with internal coatings/linings	Pressure Boundary	Gray cast iron	Treated water	Loss of material due to selective leaching	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.G.A-415	3.3-1, 140	A
Piping, piping components, heat exchanger components	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Fire Water System (B.2.1.16)	VII.G.A-722	3.3-1, 157	A
Piping, piping components, heat exchanger components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Raw water	Cracking due to SCC	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-473b	3.3-1, 160	A
Piping, piping components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Soil	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.G.A-743	3.3-1, 214	A
Piping, piping components, tanks	Pressure Boundary	Aluminum	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.C1.A-763a	3.3-1, 234	A

Table 3.3.2-7, High Pressure Fire Protection (Diesel Driven Pump) System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Sprinklers	Pressure Boundary	Metallic	Air, condensation	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	Fire Water System (B.2.1.16)	VII.G.A-403	3.3-1, 130	A

Table 3.3.2-7 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-8, Potable Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A
External surfaces	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A
Insulated piping, piping components, tanks	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Air, condensation	Loss of material due to general (steel only), pitting, crevice corrosion; cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A
Insulated piping, piping components, tanks	Pressure Boundary	Steel	Air, condensation	Loss of material due to general (steel only), pitting, crevice corrosion; cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.F2.AP-209a	3.3-1, 004	A

Table 3.3.2-8, Potable Water System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.F2.AP-221a	3.3-1, 006	A
Piping, piping components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Raw water (potable)	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.G.A-47	3.3-1, 072	A
Piping, piping components	Pressure Boundary	Stainless steel	Raw water (potable)	Loss of material due to general (steel only), pitting, crevice corrosion, flow blockage due to fouling (steel only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-270	3.3-1, 088	A
Piping, piping components	Pressure Boundary	Steel	Raw water (potable)	Loss of material due to general (steel only), pitting, crevice corrosion, flow blockage due to fouling (steel only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-270	3.3-1, 088	A
Piping, piping components	Pressure Boundary	Copper alloy	Raw water (potable)	Loss of material due to general, pitting, crevice corrosion, MIC	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-271	3.3-1, 093	A

Table 3.3.2-8 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-9, Normal Ventilation System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Metallic	Air - indoor uncontrolled	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Closure bolting HVAC	Mechanical Closure	Metallic	Air, condensation	Loss of material due to general (where applicable), pitting, crevice corrosion; cracking due to SCC, loss of preload	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.F2.A-794	3.3-1, 260	A
Ducting, ducting components (Internal surfaces)	Pressure Boundary, Structural Support	Steel	Condensation	Loss of material due to general, pitting, crevice corrosion, MIC (for drip pans and drain lines only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F2.A-08	3.3-1, 090	A
Ducting, ducting components	Pressure Boundary, Structural Support	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.F1.AP-99a	3.3-1, 094	A
Ducting, ducting components	Pressure Boundary, Structural Support	Stainless steel	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.F2.A-781a	3.3-1, 094a	A
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-9, Normal Ventilation System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Fire damper assemblies	Fire Barrier, Structural Support	Steel	Air	Loss of material due to general, pitting, crevice corrosion	Fire Protection (B.2.1.15)	VII.G.A-789	3.3-1, 255	A
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Elastomer	Air, condensation	Hardening or loss of strength due to elastomer degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3-1, 076	A
Piping, piping components, seals	Pressure Boundary	Elastomer	Air	Loss of material due to wear; flow blockage due to fouling (raw water, waste water only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F2.AP-103	3.3-1, 096	A
Piping, piping components, heat exchanger components	Pressure Boundary, Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F2.A-722	3.3-1, 157	A

Table 3.3.2-9 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-10, Air Conditioning System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Closure bolting HVAC	Mechanical Closure	Aluminum	Air, condensation	Loss of material due to general (where applicable), pitting, crevice corrosion; cracking due to SCC, loss of preload	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.F2.A-794	3.3-1, 260	A
Ducting, ducting components (Internal surfaces)	Pressure Boundary, Structural Support	Steel	Condensation	Loss of material due to general, pitting, crevice corrosion, MIC (for drip pans and drain lines only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F1.A-08	3.3-1, 090	A
Ducting, ducting components	Pressure Boundary, Structural Support	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.F1.AP-99a	3.3-1, 094	A
Ducting, ducting components	Pressure Boundary, Structural Support	Stainless steel	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.F1.A-781a	3.3-1, 094a	A

Table 3.3.2-10, Air Conditioning System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A
Fire damper assemblies	Pressure Boundary, Fire Barrier, Structural Support	Steel	Air	Loss of material due to general, pitting, crevice corrosion	Fire Protection (B.2.1.15)	VII.G.A-789	3.3-1, 255	A
Heat exchanger components	Pressure Boundary	Steel	Closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-189	3.3-1, 046	A
Heat exchanger components	Pressure Boundary	Copper alloy	Closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-203	3.3-1, 046	A
Heat exchanger components	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-40	3.3-1, 080	A
Heat exchanger components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3-1, 080	A
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Aluminum	Air, condensation	Reduction of heat transfer due to fouling	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-716	3.3-1, 151	A
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Copper alloy	Air, condensation	Reduction of heat transfer due to fouling	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-716	3.3-1, 151	A

Table 3.3.2-10, Air Conditioning System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Steel	Air, condensation	Reduction of heat transfer due to fouling	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-716	3.3-1, 151	A
Heat exchanger components	Pressure Boundary	Aluminum	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.F1.A-771a	3.3-1, 242	A
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Copper alloy	Lubricating oil	Reduction of heat transfer due to fouling	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.F1.A-791	3.3-1, 257	A
Insulated piping, piping components, tanks	Pressure Boundary, Structural Support	Steel	Air, condensation	Loss of material due to general (steel only), pitting, crevice corrosion; cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A
Piping, piping components	Pressure Boundary, Structural Support	Stainless steel	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.F4.AP-209a	3.3-1, 004	A
Piping, piping components	Pressure Boundary, Structural Support	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.F4.AP-221a	3.3-1, 006	A
Piping, piping components	Pressure Boundary, Structural Support	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F4.AP-221c	3.3-1, 006	A

Table 3.3.2-10, Air Conditioning System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components, tanks	Pressure Boundary, Structural Support	Steel	Closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3-1, 045	A
Piping, piping components, tanks	Pressure Boundary, Structural Support	Steel	Closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	VII.F4.AP-202	3.3-1, 045	A
Piping, piping components	Pressure Boundary, Structural Support	Copper alloy	Closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	VII.F1.AP-199	3.3-1, 046	A
Piping, piping components	Pressure Boundary, Structural Support	Stainless steel	Closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3-1, 049	A
Piping, piping components	Pressure Boundary, Structural Support	Copper alloy (>15% Zn or >8% Al)	Closed-cycle cooling water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.A4.AP-43	3.3-1, 072	A
Piping, piping components	Pressure Boundary, Structural Support	Gray cast iron, ductile iron	Closed-cycle cooling water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.C2.A-50	3.3-1, 072	A
Piping, piping components, seals	Pressure Boundary	Elastomer	Air, condensation	Hardening or loss of strength due to elastomer degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F4.A-504	3.3-1, 085	A

Table 3.3.2-10, Air Conditioning System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary, Structural Support	Stainless steel	Raw water (potable)	Loss of material due to general (steel only), pitting, crevice corrosion, flow blockage due to fouling (steel only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-270	3.3-1, 088	A
Piping, piping components	Pressure Boundary, Structural Support	Steel	Raw water (potable)	Loss of material due to general (steel only), pitting, crevice corrosion, flow blockage due to fouling (steel only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-270	3.3-1, 088	A
Piping, piping components	Pressure Boundary, Structural Support	Copper alloy	Raw water (potable)	Loss of material due to general, pitting, crevice corrosion, MIC	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-271	3.3-1, 093	A
Piping, piping components, seals	Pressure Boundary	Elastomer	Air	Loss of material due to wear; flow blockage due to fouling (raw water, waste water only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F4.AP-103	3.3-1, 096	A
Piping, piping components	Pressure Boundary, Structural Support	Copper alloy	Lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.C1.AP-133	3.3-1, 099	A
Piping, piping components	Pressure Boundary, Structural Support	Copper alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A
Piping, piping components	Pressure Boundary, Structural Support	Copper alloy	Gas	None	None	VII.J.AP-9	3.3-1, 114	A

Table 3.3.2-10, Air Conditioning System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping elements	Pressure Boundary	Glass	Air	None	None	VII.J.AP-48	3.3-1, 117	A
Piping elements	Pressure Boundary	Glass	Closed-cycle cooling water	None	None	VII.J.AP-166	3.3-1, 117	A
Piping elements	Pressure Boundary	Glass	Gas	None	None	VII.J.AP-98	3.3-1, 117	A
Piping, piping components	Pressure Boundary, Structural Support	Stainless steel	Gas	None	None	VII.J.AP-22	3.3-1, 120	A
Piping, piping components	Pressure Boundary, Structural Support	Steel	Air - indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	A
Piping, piping components	Pressure Boundary, Structural Support	Steel	Gas	None	None	VII.J.AP-6	3.3-1, 121	A
Piping, piping components, heat exchanger components	Pressure Boundary, Structural Support	Copper alloy (>15% Zn or >8% Al)	Closed-cycle cooling water	Cracking due to SCC	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-473a	3.3-1, 160	A
Piping, piping components, tanks	Pressure Boundary, Structural Support	Aluminum	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.F4.A-763a	3.3-1, 234	A

Table 3.3.2-10, Air Conditioning System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Polymeric	Air	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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F4.A-797b	3.3-1, 263	A

Table 3.3.2-10 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-11, Control Air System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Heat exchanger components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3-1, 080	A
Piping, piping components	Pressure Boundary, Structural Support	Nickel Alloy	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.D.AP-221a	3.3-1, 006	A
Piping, piping components	Pressure Boundary, Structural Support	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.D.AP-221a	3.3-1, 006	A
Piping, piping components, tanks	Pressure Boundary, Structural Support	Steel	Condensation	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3-1, 055	A
Piping, piping components	Pressure Boundary, Structural Support	Copper alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-11, Control Air System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components, heat exchangers, tanks with internal coatings/linings	Pressure Boundary, Structural Support	Steel with internal coatings/linings	Air-dry	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, physical damage; loss of material or cracking for cementitious coatings/linings	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.D.A-416	3.3-1, 138	C
Piping, piping components, heat exchangers, tanks with internal coatings/linings	Pressure Boundary, Structural Support	Steel with internal coatings/linings	Air-dry	Loss of material due to general, pitting, crevice corrosion, MIC	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.D.A-414	3.3-1, 139	C
Piping, piping components, tanks	Pressure Boundary, Structural Support	Aluminum	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.F4.A-763a	3.3-1, 234	A
Piping, piping components	Pressure Boundary, Structural Support	Steel	Air-dry	Loss of material due to general (steel only), pitting, crevice corrosion	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3-1, 235	A

Table 3.3.2-11 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-12, Service Air System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Insulated piping, piping components, tanks	Pressure Boundary	Steel	Air, condensation	Loss of material due to general (steel only), pitting, crevice corrosion; cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.D.AP-209a	3.3-1, 004	A
Piping, piping components, tanks	Pressure Boundary	Steel	Condensation	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3-1, 055	A
Piping, piping components	Pressure Boundary	Copper alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-12, Service Air System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components, heat exchangers with internal coatings/linings	Pressure Boundary	Steel with internal coatings/linings	Air-dry	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, physical damage; loss of material or cracking for cementitious coatings/linings	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.D.A-416	3.3-1, 138	A
Piping, piping components, heat exchangers, tanks with internal coatings/linings	Pressure Boundary	Steel with internal coatings/linings	Air-dry	Loss of material due to general, pitting, crevice corrosion, MIC	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VII.D.A-414	3.3-1, 139	A

Table 3.3.2-12 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-13, CO_2 Storage, Fire Protection/Purge System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Ducting, ducting components (Internal surfaces)	Pressure Boundary	Steel	Condensation	Loss of material due to general, pitting, crevice corrosion, MIC (for drip pans and drain lines only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F3.A-08	3.3-1, 090	A
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A
Fire damper assemblies	Pressure Boundary	Steel	Air	Loss of material due to general, pitting, crevice corrosion	Fire Protection (B.2.1.15)	VII.G.A-789	3.3-1, 255	A
Halon/carbon dioxide fire suppression system piping, piping components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Fire Protection (B.2.1.15)	VII.G.AP-150	3.3-1, 058	A

Table 3.3.2-13, CO_2 Storage, Fire Protection/Purge System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Insulated piping, piping components, tanks	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Air, condensation	Loss of material due to general (steel only), pitting, crevice corrosion; cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A
Piping, piping components	Pressure Boundary	Steel	Air	Cumulative fatigue damage due to fatigue	Section 4.3, "Metal Fatigue"	VII.E3.A-34	3.3-1, 002	A
Piping, piping components	Pressure Boundary	Nickel Alloy	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.F4.AP-221a	3.3-1, 006	A
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Elastomer	Air	Loss of material due to wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-113	3.3-1, 082	A
Piping, piping components, seals	Pressure Boundary	Elastomer	Air, condensation	Hardening or loss of strength due to elastomer degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.G.A-504	3.3-1, 085	A
Piping, piping components, seals	Pressure Boundary	Elastomer	Air	Loss of material due to wear; flow blockage due to fouling (raw water only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.G.AP-76	3.3-1, 096	A
Piping, piping components	Pressure Boundary	Copper alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A
Piping elements	Pressure Boundary	Glass	Air	None	None	VII.J.AP-48	3.3-1, 117	A
Piping, piping components	Pressure Boundary	Stainless steel	Gas	None	None	VII.J.AP-22	3.3-1, 120	A

Table 3.3.2-13, CO_2 Storage, Fire Protection/Purge System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Gas	None	None	VII.J.AP-6	3.3-1, 121	A
Piping, piping components	Pressure Boundary	Copper alloy	Air, condensation	Flow blockage due to fouling	Fire Water System (B.2.1.16)	VII.G.A-404	3.3-1, 131	A
Piping, piping components	Pressure Boundary	Aluminum	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.G.A-451a	3.3-1, 189	A
Tanks	Pressure Boundary	Steel	Gas	None	None	VII.J.AP-6	3.3-1, 121	C

Table 3.3.2-13 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-14, Station Drainage System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Waste water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	VII.E5.A-785	3.3-1, 193	A
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Stainless steel	Air - outdoor	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air - outdoor	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Closure bolting	Mechanical Closure	Stainless steel	Air	Cracking due to SCC	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3-1, 145	A
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A
Insulated piping, piping components, tanks	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Air, condensation	Loss of material due to general (steel only), pitting, crevice corrosion; cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A
Piping, piping components	Pressure Boundary	Gray cast iron, ductile iron	Waste water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.E5.A-724	3.3-1, 072	A

Table 3.3.2-14, Station Drainage System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-24	3.3-1, 080	A
Piping, piping components, heat exchanger components, tanks	Pressure Boundary	Steel	Waste water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3-1, 091	A
Piping, piping components, heat exchanger components	Pressure Boundary	Copper alloy	Waste water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-272	3.3-1, 095	A
Piping, piping components	Pressure Boundary	Copper alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A
Piping, piping components, heat exchanger components	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-722	3.3-1, 157	A

Table 3.3.2-14 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.

B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.

C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.

D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.

F. Material not in NUREG-2191 for this component.

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.

Plant Specific Notes

None.

Table 3.3.2-15, Sampling and Water Quality System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Class 1 valve bodies and bonnets	Pressure Boundary	Cast austenitic stainless steel	Reactor coolant >250°C (>482°F)	Loss of fracture toughness due to thermal aging embrittlement	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.R-08	3.1-1, 038	A
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Nickel Alloy	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Stainless steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Closure bolting	Mechanical Closure	Stainless Steel	Air	Cracking due to SCC	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3-1, 145	A
Heat exchanger Components	Pressure Boundary	Stainless steel	Treated water >60°C (>140°F)	Cracking due to SCC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-112	3.3-1, 020	A
Heat exchanger components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.F3.AP-65	3.3-1, 072	A
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Copper alloy	Air, condensation	Reduction of heat transfer due to fouling	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-716	3.3-1, 151	A

Table 3.3.2-15, Sampling and Water Quality System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Stainless steel	Air, condensation	Reduction of heat transfer due to fouling	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-716	3.3-1, 151	A
Heat exchanger Components	Pressure Boundary	Nickel Alloy	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.A4.AP-111	3.3-1, 203	A
Heat exchanger components	Pressure Boundary	Stainless Steel	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.A4.AP-111	3.3-1, 203	A
Heat exchanger components	Pressure Boundary	Nickel Alloy	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.F3.A-770a	3.3-1, 241	A
Insulated piping, piping components, tanks	Pressure Boundary	Stainless Steel	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.I.A-734b	3.3-1, 205	A
Piping, piping components	Pressure Boundary	Stainless Steel	Any	Cumulative fatigue damage due to fatigue	Section 4.3, “Metal Fatigue”	VII.E3.A-62	3.3-1, 002	A
Piping, piping components	Pressure Boundary	Steel	Any	Cumulative fatigue damage due to fatigue	Section 4.3, “Metal Fatigue	VII.E3.A-34	3.3-1, 002	A
Piping, piping components	Pressure Boundary	Stainless Steel	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.C2.AP-209a	3.3-1, 004	A
Piping, piping components	Pressure Boundary	Nickel Alloy	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.C2.AP-221a	3.3-1, 006	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.C2.AP-221a	3.3-1, 006	A
Piping, piping components	Pressure Boundary	Steel	Treated Water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-106	3.3-1, 021	A
Piping, piping components	Pressure Boundary	Copper Alloy	Treated Water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-140	3.3-1, 022	A

Table 3.3.2-15, Sampling and Water Quality System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Raw Water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3-1, 037	A
Piping, piping components	Pressure Boundary	Stainless Steel	Raw Water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3-1, 040	A
Piping, piping components, tanks	Pressure Boundary	Steel	Condensation	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3-1, 055	A
Piping, piping components	Pressure Boundary	Gray cast iron, ductile iron	Treated Water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.E3.AP-31	3.3-1, 072	A
Piping, piping components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Treated Water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.E3.AP-32	3.3-1, 072	A
Piping, piping components	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-24	3.3-1, 080	A
Piping, piping components	Pressure Boundary	Copper Alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A
Piping elements	Pressure Boundary	Glass	Air	None	None	VII.J.AP-48	3.3-1, 117	A
Piping elements	Pressure Boundary	Glass	Treated Water	None	None	VII.J.AP-51	3.3-1, 117	A
Piping, piping components	Pressure Boundary	Steel	Air - indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	A

Table 3.3.2-15, Sampling and Water Quality System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Gas	None	None	VII.J.AP-6	3.3-1, 121	A
Piping, piping components, heat exchanger components (for components not covered by NRC GL 89-13)	Pressure Boundary	Stainless steel	Raw Water	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-727	3.3-1, 134	A
Piping, piping components - RCPB	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Piping, piping components	Pressure Boundary	Nickel Alloy	Treated Water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-110	3.3-1, 203	A
Piping, piping components	Pressure Boundary	Stainless steel	Treated Water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-110	3.3-1, 203	A
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Polymeric	Air, condensation	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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C2.A-797b	3.3-1, 263	A

Table 3.3.2-15, Sampling and Water Quality System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Polymeric	Treated Water	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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C2.A-797b	3.3-1, 263	A
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Polymeric	Air, condensation	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	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797a	3.3-1, 263	A
Reactor coolant pressure boundary components	Pressure Boundary	Stainless Steel	Reactor coolant	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	A

Table 3.3.2-15, Sampling and Water Quality System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Reactor coolant system components: Components defined as ASME Section XI components (e.g., reactor coolant pressure boundary components, core support structure components, ASME Class 2 or 3 components, including associated pressure-retaining welds) not managed by other AMR line items in GALL-SLR Chapter IV	Pressure Boundary	Stainless steel	Treated water	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) and Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A

Table 3.3.2-15 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-16, Building Heating System - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Any	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
External Surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A
Heat exchanger Components	Pressure Boundary	Steel	Closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	VII.A4.AP-189	3.3-1, 046	A
Heat exchanger Components	Pressure Boundary	Copper Alloy	Closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	VII.F3.AP-203	3.3-1, 046	A
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Steel	Closed-cycle cooling water	Reduction of heat transfer due to fouling	Closed Treated Water Systems (B.2.1.12)	VII.F2.AP-204	3.3-1, 050	A
Heat exchanger Components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3-1, 080	A
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Copper Alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	C

Table 3.3.2-16, Building Heating System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Copper Alloy	Air, condensation	Reduction of heat transfer due to fouling	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-716	3.3-1, 151	A
Piping, piping components, tanks	Pressure Boundary	Steel	Closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	VII.F3.AP-202	3.3-1, 045	A

Table 3.3.2-16 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-17, Hypochlorite System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Raw Water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3-1, 193	A
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Steel	Air - outdoor	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Piping, piping components	Pressure Boundary, Structural Support	Stainless Steel	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.C1.AP-209a	3.3-1, 004	A
Piping, piping components	Pressure Boundary, Structural Support	Nickel Alloy	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.C1.AP-221a	3.3-1, 006	A
Piping, piping components	Pressure Boundary, Structural Support	Nickel Alloy	Raw Water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-206	3.3-1, 034	A
Piping, piping components	Pressure Boundary, Structural Support	Steel	Raw Water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3-1, 037	A
Piping, Piping Components	Pressure Boundary, Structural Support	Stainless Steel	Raw Water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3-1, 040	A

Table 3.3.2-17, Hypochlorite System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary, Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-24	3.3-1, 080	A
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Polymeric	Raw Water	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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-797b	3.3-1, 263	A

Table 3.3.2-17 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-18, Demineralizer Backwash Air System - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
External Surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A
Piping, piping components, tanks	Pressure Boundary	Steel	Condensation	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3-1, 055	A
Piping, piping components	Pressure Boundary	Copper Alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A
Piping, Piping Components	Pressure Boundary	Cast Iron	Air-dry	Loss of material due to general (steel only), pitting, crevice corrosion	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3-1, 235	A
Piping, piping components	Pressure Boundary	Copper Alloy	Air-dry	Loss of material due to general (steel only), pitting, crevice corrosion	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3-1, 235	A
Piping, Piping Components	Pressure Boundary	Steel	Air-dry	Loss of material due to general (steel only), pitting, crevice corrosion	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3-1, 235	A

Table 3.3.2-18 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-19, Standby Liquid Control System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Treated water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	VII.E2.A-439	3.3-1, 193	A
Class 1 piping, fittings and branch connections < NPS 4	Pressure Boundary	Stainless steel	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), thermal, mechanical, vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) Water Chemistry (B.2.1.2) and ASME Code Class 1 Small-bore Piping (B.2.1.22)	IV.C1.RP-230	3.1-1, 039	A
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Closure bolting	Mechanical Closure	Stainless steel	Air	Cracking due to SCC	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3-1, 145	A
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A
Insulated piping, piping components, tanks	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.I.A-761b	3.3-1, 232	A

Table 3.3.2-19, Standby Liquid Control System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping Components	Pressure Boundary	Stainless Steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Piping, piping components	Pressure Boundary	Stainless steel	Treated Water	Cumulative fatigue damage due to fatigue	Section 4.3, "Metal Fatigue"	VII.E3.A-62	3.3-1, 002	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.C2.AP-221a	3.3-1, 006	A
Piping, piping components	Pressure Boundary	Aluminum	Treated water	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-130	3.3-1, 025	A
Piping, piping components	Pressure Boundary	Steel	Lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.C2.AP-127	3.3-1, 097	A
Piping, piping components	Pressure Boundary	Copper alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A
Piping, piping components	Pressure Boundary	Steel	Air - indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	A
Piping, piping components, tanks	Pressure Boundary	Aluminum	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.E2.A-451a	3.3-1, 189	A
Piping, piping components, tanks	Pressure Boundary	Stainless steel	Sodium pentaborate solution	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E2.AP-141	3.3-1, 203	A
Piping, piping components, tanks	Pressure Boundary	Steel	Sodium pentaborate solution	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E2.AP-141	3.3-1, 203	F, 1
Reactor coolant pressure boundary components	Pressure Boundary	Stainless steel	Reactor coolant	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	A

<u>Table 3.3.2-19 Notes</u>

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. The Water Chemistry program (B.2.1.2) (relating to Standby Liquid Control) is used to manage the aging effect(s) applicable to this component type, material and environment combination.

Table 3.3.2-20, Off-Gas System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Ducting, ducting components (Internal surfaces)	Pressure Boundary	Steel	Condensation	Loss of material due to general, pitting, crevice corrosion, MIC (for drip pans and drain lines only)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F3.A-08	3.3-1, 090	A
External Surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A
Piping, piping components	Pressure Boundary	Steel	Air	Cumulative fatigue damage due to fatigue	Section 4.3, “Metal Fatigue”	VII.E3.A-34	3.3-1, 002	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, Condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.C2.AP-221a	3.3-1, 006	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, Condensation	Loss of material due to pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.C2.AP-221b	3.3-1, 006	A
Piping, piping components, tanks	Pressure Boundary	Steel	Condensation	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3-1, 055	A

Table 3.3.2-20, Off-Gas System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Copper Alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-20 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-21, Emergency Equipment Cooling Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Raw water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	VII.C1.A-532	3.3-1, 193	A
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	stainless steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Soil	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Heat exchanger components	Pressure Boundary	Copper alloy	Raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3-1, 038	A
Heat exchanger components	Pressure Boundary	Steel	Raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3-1, 038	A
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Copper Alloy	Raw Water	Cracking due to SCC (titanium only), Reduction of heat transfer due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-187	3.3-1, 042	A
Heat exchanger components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Raw water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.C1.A-66	3.3-1, 072	A

Table 3.3.2-21, Emergency Equipment Cooling Water System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Heat exchanger components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3-1, 080	A
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Copper alloy	Air, condensation	Reduction of heat transfer due to fouling	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-716	3.3-1, 151	A
Heat exchanger components	Pressure Boundary	Aluminum	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.F3.A-771a	3.3-1, 242	A
Insulated piping, piping components, tanks	Pressure Boundary	Steel	Air, condensation	Loss of material due to general (steel only), pitting, crevice corrosion; cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A
Insulated piping, piping components, tanks	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.I.A-761b	3.3-1, 232	A
Piping, piping components	Pressure Boundary	Stainless Steel	Air	Cumulative fatigue damage due to fatigue	Section 4.3, “Metal Fatigue”	VII.E3.A-62	3.3-1, 002	A
Piping, piping components	Pressure Boundary	Stainless Steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.C2.AP-221a	3.3-1, 006	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.C2.AP-221b	3.3-1, 006	A
Piping, piping components	Pressure Boundary	Copper alloy	Raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3-1, 034	A

Table 3.3.2-21, Emergency Equipment Cooling Water System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3-1, 037	A
Piping, piping components	Pressure Boundary	Stainless steel	Raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3-1, 040	A
Piping, piping components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Raw water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.C1.A-47	3.3-1, 072	A
Piping, piping components	Pressure Boundary	Gray cast iron, ductile iron	Raw water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.C1.A-51	3.3-1, 072	A
Piping, piping components	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-24	3.3-1, 080	A
Piping, piping components	Pressure Boundary	Steel	Concrete	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-198	3.3-1, 109	B
Piping, piping components	Pressure Boundary	Steel	Soil	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-198	3.3-1, 109	B
Piping, piping components	Pressure Boundary	Steel	Concrete	None	None	VII.J.AP-282	3.3-1, 112	A
Piping, piping components	Pressure Boundary	Copper alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A
Piping, piping components	Pressure Boundary	Copper alloy	Gas	None	None	VII.J.AP-9	3.3-1, 114	A

Table 3.3.2-21, Emergency Equipment Cooling Water System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping elements	Pressure Boundary	Glass	Raw water	None	None	VII.J.AP-50	3.3-1, 117	A
Piping, piping components, heat exchanger components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Raw water	Cracking due to SCC	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-473b	3.3-1, 160	A

Table 3.3.2-21 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.

B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.

C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.

D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.

F. Material not in NUREG-2191 for this component.

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.

Plant Specific Notes

None.

Table 3.3.2-22, Reactor Water Cleanup System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Treated Water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	VII.E3.A-439	3.3-1, 193	A
Class 1 valve bodies and bonnets	Pressure Boundary	Cast austenitic stainless steel	Reactor coolant >250°C (>482°F)	Loss of fracture toughness due to thermal aging embrittlement	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.R-08	3.1-1, 038	A
Class 1 piping, fittings and branch connections < NPS 4	Pressure Boundary	Stainless steel	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), thermal, mechanical, vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) Water Chemistry (B.2.1.2) and ASME Code Class 1 Small-bore Piping (B.2.1.22)	IV.C1.RP-230	3.1-1, 039	A
Class 1 piping, fittings and branch connections < NPS 4	Pressure Boundary	Steel	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), thermal, mechanical, vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1) Water Chemistry (B.2.1.2) and ASME Code Class 1 Small-bore Piping (B.2.1.22)	IV.C1.RP-230	3.1-1, 039	A
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A

Table 3.3.2-22, Reactor Water Cleanup System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Closure bolting	Mechanical Closure	Stainless Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure Bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Stainless Steel	Air - indoor uncontrolled	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Closure bolting	Mechanical Closure	Stainless Steel	Air	Cracking due to SCC	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3-1, 145	A
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A
Heat exchanger components	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.E.SP-77	3.4-1, 015	A
Heat exchanger components	Pressure Boundary	Stainless steel	Treated water >60°C (>140°F)	Cracking due to SCC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-112	3.3-1, 020	A
Heat exchanger components	Pressure Boundary	Gray cast iron, ductile iron	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.C2.AP-31	3.3-1, 072	C, 1
Heat exchanger components	Pressure Boundary	Steel	Air - indoor Uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3-1, 080	A

Table 3.3.2-22, Reactor Water Cleanup System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Stainless steel	Air, condensation	Reduction of heat transfer due to fouling	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-716	3.3-1, 151	A
Heat exchanger components	Pressure Boundary	Stainless steel	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.A4.AP-111	3.3-1, 203	A
Insulated piping, piping components, tanks	Pressure Boundary	Steel	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)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A
Insulated piping, piping components, tanks	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.I.A-761b	3.3-1, 232	A
Piping, piping components	Pressure Boundary	Steel	Reactor coolant	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-23	3.1-1, 060	A
Piping, piping components greater than or equal to 4 NPS	Pressure Boundary	Stainless Steel	Reactor Coolant	Cracking due to SCC, IGSCC	BWR Stress Corrosion Cracking (B.2.1.5) and Water Chemistry (B.2.1.2)	IV.C1.R-20	3.1-1, 097	B
Piping, piping components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Piping, piping components	Pressure Boundary	Stainless Steel	Air	Cumulative fatigue damage due to fatigue	Section 4.3, “Metal Fatigue”	VII.E3.A-62	3.3-1, 002	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.C2.AP-209a	3.3-1, 004	A

Table 3.3.2-22, Reactor Water Cleanup System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.C2.AP-221b	3.3-1, 006	A
Piping, piping components outboard the second containment isolation valves with a diameter ≥ 4 inches nominal pipe size	Pressure Boundary	Stainless steel	Treated water >93°C (>200°F)	Cracking due to SCC, IGSCC	Water Chemistry (B.2.1.2)	VII.E3.AP-283	3.3-1, 016	A,3
Piping, piping components	Pressure Boundary	Steel	Treated Water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-106	3.3-1, 021	A
Piping, piping components	Pressure Boundary	Copper alloy	Treated Water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-140	3.3-1, 022	A
Piping, piping components, tanks	Pressure Boundary	Steel	Condensation	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-26	3.3-1, 055	A
Piping, piping components	Pressure Boundary	Gray cast iron, ductile iron	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.E3.AP-31	3.3-1, 072	A
Piping, piping components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.E3.AP-32	3.3-1, 072	A
Piping, piping components	Pressure Boundary	Steel	Air-indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-24	3.3-1, 080	G, 2
Piping, piping components	Pressure Boundary	Copper alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A

Table 3.3.2-22, Reactor Water Cleanup System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping elements	Pressure Boundary	Glass	Air	None	None	VII.J.AP-48	3.3-1, 117	A
Piping elements	Pressure Boundary	Glass	Treated Water	None	None	VII.J.AP-51	3.3-1, 117	A
Piping, piping components	Pressure Boundary	Stainless Steel	Gas	None	None	VII.J.AP-22	3.3-1, 120	A
Piping, piping components	Pressure Boundary	Steel	Air - indoor Controlled	None	None	VII.J.AP-2	3.3-1, 121	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	VII.E3.A-408	3.3-1, 126	A
Piping, piping components	Pressure Boundary	Stainless Steel	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-110	3.3-1, 203	A
Piping, piping Components	Pressure Boundary	Stainless steel	Treated water >60°C (>140°F)	Cracking due to SCC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.A-773	3.3-1, 244	A
Tanks	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.E.SP-75	3.4-1, 012	A
Tanks	Pressure Boundary	Stainless steel	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.E.SP-162	3.4-1, 083	A

Table 3.3.2-22 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. The Selective Leaching program (B.2.1.21) program is used to manage the aging effect(s) applicable to this component type, material and environment combination.
2. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) is used to manage the aging effect(s) applicable to this component type, material and environment combination.
3. The Water Chemistry program (B.2.1.2) will be used to manage the aging effect(s) applicable to this component type, material and environment combination. The AMP XI.M25, BWR Reactor Water Cleanup System, will not be used since BFN Units 1, 2, and 3 have satisfactorily completed all actions requested in NRC GL 89-10 and NRC GL 88-01 for the Reactor Water Cleanup (RWCU) System. NRC has documented closeout of these GLs for BFN. In addition, the RWCU piping on each unit has been replaced with piping made of material that is resistant to IGSCC. Therefore, consistent with NRC guidance, no IGSCC inspections are required.

Table 3.3.2-23, Reactor Building Closed Cooling Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A
Heat exchanger components	Pressure Boundary	Steel	Closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3-1, 046	A
Heat exchanger components	Pressure Boundary	Steel	Air - indoor Uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3-1, 080	A
Heat exchanger tubes internal to components	Pressure Boundary, Heat Transfer	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F3.A-778	3.3-1, 249	A
Insulated piping, piping components, tanks	Pressure Boundary	Steel	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)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A

Table 3.3.2-23, Reactor Building Closed Cooling Water System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless steel	Air, Condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.C2.AP-209a	3.3-1, 004	A
Piping, piping components	Pressure Boundary	Nickel Alloy	Air, Condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.C2.AP-221a	3.3-1, 006	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, Condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.C2.AP-221a	3.3-1, 006	A
Piping, piping components, tanks	Pressure Boundary	Steel	Closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3-1, 045	A
Piping, piping components	Pressure Boundary	Copper alloy	Closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3-1, 046	A
Piping, piping components, tanks	Pressure Boundary	Steel	Condensation	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-26	3.3-1, 055	A
Piping, piping components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Closed-cycle cooling water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.C2.AP-43	3.3-1, 072	A
Piping, piping components	Pressure Boundary	Copper Alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A
Piping, piping components	Pressure Boundary	Stainless steel	Gas	None	None	VII.J.AP-22	3.3-1, 120	A
Piping, piping components	Pressure Boundary	Steel	Gas	None	None	VII.J.AP-6	3.3-1, 121	A
Piping, piping components, heat exchanger components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Closed-cycle cooling water	Cracking due to SCC	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-473a	3.3-1, 160	A

Table 3.3.2-23, Reactor Building Closed Cooling Water System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Piping, piping components, tanks	Pressure Boundary	Aluminum	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.C2.A-451a	3.3-1, 189	A
Piping, piping components	Pressure Boundary	Steel	Air-dry	Loss of material due to general (steel only), pitting, crevice corrosion	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3-1, 235	A

Table 3.3.2-23 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-24, Auxiliary Decay Heat Removal System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure Bolting	Mechanical Closure	Stainless Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Heat exchanger components	Pressure Boundary	Stainless steel	Closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	VII.E3.AP-191	3.3-1, 047	A
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Stainless steel	Air, condensation	Reduction of heat transfer due to fouling	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-716	3.3-1, 151	A
Heat exchanger components	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.F2.A-770a	3.3-1, 241	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, Condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.C2.AP-221a	3.3-1, 006	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, Condensation	Loss of material due to pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.C2.AP-221b	3.3-1, 006	A
Piping, piping components	Pressure Boundary	Stainless Steel	Closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3-1, 049	A

Table 3.3.2-24, Auxiliary Decay Heat Removal System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless Steel	Gas	None	None	VII.J.AP-22	3.3-1, 120	A

Table 3.3.2-24 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-25, Containment Inerting System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure Bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
External surfaces	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A
Heat exchanger components	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.F3.A-770a	3.3-1, 241	A
Insulated piping, piping components, tanks	Pressure Boundary	Stainless Steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.I.A-761b	3.3-1, 232	A
Piping, piping components	Pressure Boundary	Nickel Alloy	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.F3.AP-221a	3.3-1, 006	A
Piping, piping components, tanks	Pressure Boundary	Steel	Condensation	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F3.A-26	3.3-1, 055	A
Piping, piping components	Pressure Boundary	Aluminum	Gas	None	None	VII.J.AP-37	3.3-1, 113	A
Piping, piping components	Pressure Boundary	Copper Alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A
Piping, piping components	Pressure Boundary	Copper Alloy	Gas	None	None	VII.J.AP-9	3.3-1, 114	A

Table 3.3.2-25, Containment Inerting System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless Steel	Gas	None	None	VII.J.AP-22	3.3-1, 120	A
Piping, piping components, tanks	Pressure Boundary	Aluminum	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.F4.A-763a	3.3-1, 234	A

Table 3.3.2-25 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-26, Radwaste System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Treated Water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	VII.E3.A-439	3.3-1, 193	A
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure Bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Metallic	Air	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Heat exchanger Components	Pressure Boundary	Stainless steel	Treated water >60°C (>140°F)	Cracking due to SCC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-112	3.3-1, 020	A
Heat exchanger components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3-1, 080	A
Heat exchanger Components	Pressure Boundary	Stainless steel	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.A4.AP-111	3.3-1, 203	A
Insulated piping, piping components, tanks	Pressure Boundary	Steel	Air, condensation	Loss of material due to general (steel only), pitting, crevice corrosion; cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.C2.AP-221a	3.3-1, 006	A

Table 3.3.2-26, Radwaste System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-106	3.3-1, 021	A
Piping, piping components	Pressure Boundary	Copper Alloy	Treated Water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.A4.AP-140	3.3-1, 022	A
Piping, piping components, heat exchanger components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Waste water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.E5.A-547	3.3-1, 072	A
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Elastomer	Air, condensation	Hardening or loss of strength due to elastomer degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3-1, 076	A
Piping, piping components	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-24	3.3-1, 080	A
Piping, piping components, seals	Pressure Boundary	Elastomer	Air, condensation	Hardening or loss of strength due to elastomer degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-504	3.3-1, 085	A
Piping, piping components, heat exchanger components, tanks	Pressure Boundary	Steel	Waste Water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-281	3.3-1, 091	A
Piping, piping components, tanks	Pressure Boundary	Stainless steel	Waste Water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.AP-278	3.3-1, 095	A

Table 3.3.2-26, Radwaste System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Concrete	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-198	3.3-1, 109	B
Piping, piping components	Pressure Boundary	Steel	Concrete	None	None	VII.J.AP-282	3.3-1, 112	A
Piping, piping components	Pressure Boundary	Copper Alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A
Piping, piping components	Pressure Boundary	Copper Alloy	Gas	None	None	VII.J.AP-9	3.3-1, 114	A
Piping, piping components	Pressure Boundary	Stainless steel	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-110	3.3-1, 203	A
Piping, piping components	Pressure Boundary	Copper alloy	Lubricating oil (waste oil)	Loss of material due to general, pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	VII.G.AP-117	3.3-1, 250	J, 1
Piping, piping components	Pressure Boundary	Steel	Lubricating oil (waste oil)	Loss of material due to general, pitting, crevice corrosion, MIC	One-Time Inspection (B.2.1.20)	VII.G.AP-117	3.3-1, 250	C, 1

Table 3.3.2-26 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.

B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.

C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.

D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.

F. Material not in NUREG-2191 for this component.

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.

Plant Specific Notes

1. The One-Time Inspection program (B.2.1.20) is used to manage the aging effect(s) applicable to this component type, material and environment combination.

Table 3.3.2-27, Spent Fuel Pool Cooling/Cleanup System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Treated Water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	VII.A4.A-439	3.3-1, 193	A
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure Bolting	Mechanical Closure	Stainless steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Closure bolting	Mechanical Closure	Stainless steel	Treated 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)	Bolting Integrity (B.2.1.10)	VII.I.A-423	3.3-1, 142	A, 1
Closure bolting	Mechanical Closure	Steel	Treated 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)	Bolting Integrity (B.2.1.10)	VII.I.A-423	3.3-1, 142	A, 1
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A

Table 3.3.2-27, Spent Fuel Pool Cooling/Cleanup System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Heat exchanger components	Pressure Boundary	Steel	Air - indoor Uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3-1, 080	A
Insulated piping, piping components, tanks	Pressure Boundary	Steel	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)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A
Insulated piping, piping components, tanks	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.I.A-761b	3.3-1, 232	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.C2.AP-221a	3.3-1, 006	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.C2.AP-221b	3.3-1, 006	A
Piping, piping components	Pressure Boundary	Aluminum	Treated Water	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.A4.AP-130	3.3-1, 025	A
Piping, piping components	Pressure Boundary	Aluminum	Treated water	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.C2.AP-130	3.3-1, 025	A
Piping, piping components	Pressure Boundary	Gray cast iron, ductile iron	Treated Water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.A4.AP-31	3.3-1, 072	A
Piping, piping components	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-24	3.3-1, 080	A
Piping, piping components	Pressure Boundary	Steel	Concrete	None	None	VII.J.AP-282	3.3-1, 112	A

Table 3.3.2-27, Spent Fuel Pool Cooling/Cleanup System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components, tanks	Pressure Boundary	Stainless steel	Underground	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.I.A-714a	3.3-1, 146	A
Piping, piping components	Pressure Boundary	Stainless steel	Concrete	None	None	VII.J.AP-19	3.3-1, 202	A
Piping, piping components	Pressure Boundary	Stainless steel	Treated Water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.A4.AP-110	3.3-1, 203	A
Piping, piping components, tanks	Pressure Boundary	Aluminum	Air, Condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.A4.A-763a	3.3-1, 234	A
Piping, piping components, tanks	Pressure Boundary	Stainless steel	Underground	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.I.A-775a	3.3-1, 246	A
Tanks	Pressure Boundary	Stainless steel	Treated Water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.E.SP-162	3.4-1, 083	A

Table 3.3.2-27 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. This GALL-SLR item reflects consideration of leakage from a flanged connection. However, this system does not contain any submerged closure bolting.

Table 3.3.2-28, Fuel Handling and Storage System - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Cranes: rails, bridges, structural members, structural components	Structural Support	Aluminum	Air	Loss of material due to general corrosion, wear, deformation, cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3-1, 052	F, 1
Cranes: rails, bridges, structural members, structural components	Structural Support	Aluminum	Treated Water	Loss of material due to general corrosion, wear, deformation, cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3-1, 052	F, G, 1
Cranes: rails, bridges, structural members, structural components	Structural Support	Stainless steel	Treated Water	Loss of material due to general corrosion, wear, deformation, cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3-1, 052	F, G, 1
Cranes: rails, bridges, structural members, structural components	Structural Support	Steel	Air	Loss of material due to general corrosion, wear, deformation, cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3-1, 052	A
Cranes: structural bolting	Structural Support	High-strength steel	Air	Loss of preload due to self-loosening; loss of material due to general corrosion; cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-730	3.3-1, 199	F, 1
Cranes: structural bolting	Structural Support	Stainless Steel	Air	Loss of preload due to self-loosening; loss of material due to general corrosion; cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-730	3.3-1, 199	F, 1

Table 3.3.2-28, Fuel Handling and Storage System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Cranes: structural bolting	Structural Support	Stainless Steel	Treated Water	Loss of preload due to self-loosening; loss of material due to general corrosion; cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-730	3.3-1, 199	F, G, 1
Cranes: structural bolting	Structural Support	Steel	Air	Loss of preload due to self-loosening; loss of material due to general corrosion; cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-730	3.3-1, 199	A
Spent fuel storage racks: neutron-absorbing sheets (BWR)	Absorbs neutrons	Boral®; boron steel, and other materials (excluding Boraflex)	Treated water	Reduction of neutron-absorbing capacity; change in dimensions and loss of material due to effects of SFP environment	Monitoring of Neutron-Absorbing Materials other than Boraflex (B.2.1.26)	VII.A2.AP-236	3.3-1, 102	A
Spent fuel storage racks (BWR)	Structural Support	Stainless steel	Treated water >60°C (>140°F)	Cracking due to SCC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.A2.A-96	3.3-1, 124	A
Spent fuel storage racks (BWR)	Structural Support	Stainless steel	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.A2.A-98	3.3-1, 125	A

Table 3.3.2-28 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program (B.2.1.13) is used to manage the aging effect(s) applicable to this component type, material and environment combination.

Table 3.3.2-29, Standby Diesel Generators - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Structural Support	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure Bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A
Heat exchanger components	Pressure Boundary	Steel	Closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3-1, 046	A
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Copper Alloy	Closed-cycle cooling water	Reduction of heat transfer due to fouling	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-205	3.3-1, 050	A
Heat exchanger components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.F3.AP-65	3.3-1, 072	A
Heat exchanger components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3-1, 080	A
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Aluminum	Lubricating Oil	Reduction of heat transfer due to fouling	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.H2.AP-154	3.3-1, 101	A

Table 3.3.2-29, Standby Diesel Generators - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat exchanger components	Pressure Boundary	Aluminum	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.F4.A-771a	3.3-1, 242	A
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Copper Alloy	Lubricating Oil	Reduction of heat transfer due to fouling	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.H2.A-791	3.3-1, 257	A
Insulated piping, piping components, tanks	Pressure Boundary	Steel	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)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A
Piping, piping components	Pressure Boundary	Steel	Air	Cumulative fatigue damage due to fatigue	Section 4.3, "Metal Fatigue"	VII.E3.A-34	3.3-1, 002	A
Piping, piping components	Pressure Boundary	Stainless Steel	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.H2.AP-209a	3.3-1, 004	A
Piping, piping components, tanks	Pressure Boundary	Steel	Closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-202	3.3-1, 045	A
Piping, piping components	Pressure Boundary	Copper Alloy	Closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-199	3.3-1, 046	A
Piping, piping components	Pressure Boundary	Stainless Steel	Closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3-1, 049	A
Piping, piping components, tanks	Pressure Boundary	Steel	Condensation	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.A-26	3.3-1, 055	A
Piping, piping components	Pressure Boundary	Gray cast iron, ductile iron	Closed-cycle cooling water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.C2.A-50	3.3-1, 072	A

Table 3.3.2-29, Standby Diesel Generators - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Piping, piping components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Closed-cycle cooling water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.H2.AP-43	3.3-1, 072	A
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Elastomer	Air, condensation	Hardening or loss of strength due to elastomer degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3-1, 076	A
Piping, piping components	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-24	3.3-1, 080	A
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Elastomer	Air	Loss of material due to wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-113	3.3-1, 082	A
Piping, piping components, seals	Pressure Boundary	Elastomer	Closed-cycle cooling water	Hardening or loss of strength due to elastomer degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C2.AP-259	3.3-1, 085	A
Piping, piping components, seals	Pressure Boundary	Elastomer	Gas	Hardening or loss of strength due to elastomer degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.A-729	3.3-1, 085	A
Piping, piping components, diesel engine exhaust	Pressure Boundary	Steel	Diesel exhaust	Loss of material due to general (steel only), pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.AP-104	3.3-1, 088	A

Table 3.3.2-29, Standby Diesel Generators - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.H2.AP-127	3.3-1, 097	A
Piping, piping components	Pressure Boundary	Copper Alloy	Lubricating Oil	Loss of material due to pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.H2.AP-133	3.3-1, 099	A
Piping, piping components	Pressure Boundary	Stainless Steel	Lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.H2.AP-138	3.3-1, 100	A
Piping, piping components	Pressure Boundary	Copper Alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A
Piping, piping components	Pressure Boundary	Copper Alloy	Gas	None	None	VII.J.AP-9	3.3-1, 114	A
Piping elements	Pressure Boundary	Glass	Lubricating Oil	None	None	VII.J.AP-15	3.3-1, 117	A
Piping elements	Pressure Boundary	Glass	Air	None	None	VII.J.AP-48	3.3-1, 117	A
Piping elements	Pressure Boundary	Glass	Closed-cycle cooling water	None	None	VII.J.AP-166	3.3-1, 117	A
Piping elements	Pressure Boundary	Glass	Gas	None	None	VII.J.AP-98	3.3-1, 117	A
Piping, piping components	Pressure Boundary	Steel	Air - indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	A
Piping, piping components	Pressure Boundary	Steel	Gas	None	None	VII.J.AP-6	3.3-1, 121	A

Table 3.3.2-29 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-30, Supplemental Diesel Generator System - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A
Heat exchanger components	Pressure Boundary	Steel	Closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3-1, 046	A
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Aluminum	Closed-cycle cooling water	Reduction of heat transfer due to fouling	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-188	3.3-1, 050	F, 1
Heat exchanger components	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-40	3.3-1, 080	A
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Aluminum	Air	Reduction of heat transfer due to fouling	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-716	3.3-1, 151	A

Table 3.3.2-30, Supplemental Diesel Generator System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Insulated piping, piping components, tanks	Pressure Boundary	Steel	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)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A
Piping, piping components	Pressure Boundary	Stainless Steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.H2.AP-221a	3.3-1, 006	A
Piping, piping components, tanks	Pressure Boundary	Steel	Closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-202	3.3-1, 045	A
Piping, piping components, tanks	Pressure Boundary	Steel	Fuel Oil	Loss of material due to general, pitting, crevice corrosion, MIC	Fuel Oil Chemistry (B.2.1.18)	VII.H2.AP-105a	3.3-1, 070	B
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Elastomer	Air, condensation	Hardening or loss of strength due to elastomer degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3-1, 076	A
Piping, piping components, seals	Pressure Boundary	Elastomer	Closed-cycle cooling water	Hardening or loss of strength due to elastomer degradation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C2.AP-259	3.3-1, 085	A
Piping, piping components, diesel engine exhaust	Pressure Boundary	Stainless Steel	Diesel Exhaust	Loss of material due to general (steel only), pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.AP-104	3.3-1, 088	A
Piping, piping components, diesel engine exhaust	Pressure Boundary	Steel	Diesel Exhaust	Loss of material due to general (steel only), pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.AP-104	3.3-1, 088	A

Table 3.3.2-30, Supplemental Diesel Generator System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.H2.AP-127	3.3-1, 097	A

Table 3.3.2-30 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. The Closed Treated Water Systems program (B.2.1.12) is used to manage the aging effect(s) applicable to this component type, material, and environment combination.

Table 3.3.2-31, Control Rod Drive System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Treated Water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	VII.E3.A-439	3.3-1, 193	A
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A
Heat exchanger components	Pressure Boundary	Steel	Air - indoor Uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-41	3.3-1, 080	A
Heat exchanger Tubes	Pressure Boundary, Heat Transfer	Copper alloy	Air, condensation	Reduction of heat transfer due to fouling	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-716	3.3-1, 151	A
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Copper alloy	Lubricating oil	Reduction of heat transfer due to fouling	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.C1.A-791	3.3-1, 257	A
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Steel	Lubricating oil	Reduction of heat transfer due to fouling	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.C1.A-791	3.3-1, 257	A

Table 3.3.2-31, Control Rod Drive System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Insulated piping, piping components, tanks	Pressure Boundary	Steel	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)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A
Insulated piping, piping components, tanks	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	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)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A
Insulated piping, piping components, tanks	Pressure Boundary	Stainless steel	Air, Condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.I.A-761b	3.3-1, 232	A
Piping, piping components	Pressure Boundar	Steel	Air	Cumulative fatigue damage due to fatigue	Section 4.3, “Metal Fatigue”	VII.E3.A-34	3.3-1, 002	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.C2.AP-221b	3.3-1, 006	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.D.AP-221c	3.3-1, 006	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-106	3.3-1, 021	A
Piping, piping components	Pressure Boundary	Aluminum	Treated Water	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-130	3.3-1, 025	A

Table 3.3.2-31, Control Rod Drive System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.E3.AP-32	3.3-1, 072	A
Piping, piping components	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-24	3.3-1, 080	A
Piping, piping components	Pressure Boundary	Steel	Lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.C2.AP-127	3.3-1, 097	A
Piping, piping components	Pressure Boundary	Copper Alloy	Lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.C2.AP-133	3.3-1, 099	A
Piping, piping components	Pressure Boundary	Copper Alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A
Piping, piping components	Pressure Boundary	Stainless steel	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.E3.AP-110	3.3-1, 203	A
Piping, piping components, tanks	Pressure Boundary	Aluminum	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.E5.A-763a	3.3-1, 234	A
Tanks	Pressure Boundary	Stainless steel	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.E.SP-162	3.4-1, 083	A

Table 3.3.2-31 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-32, Diesel Generator Starting Air System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Insulated piping, piping components, tanks	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	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)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A
Insulated piping, piping components, tanks	Pressure Boundary	Steel	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)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-405a	3.3-1, 132	A
Piping, piping components	Pressure Boundary	Stainless Steel	Air, condensation	Cracking due to SCC	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.H2.AP-209b	3.3-1, 004	A
Piping, piping components, tanks	Pressure Boundary	Steel	Condensation	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.H2.A-26	3.3-1, 055	A

Table 3.3.2-32, Diesel Generator Starting Air System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Elastomer	Air, condensation	Hardening or loss of strength due to elastomer degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3-1, 076	A
Piping, piping components	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-24	3.3-1, 080	A
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Elastomer	Air	Loss of material due to wear	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-113	3.3-1, 082	A
Piping, piping components	Pressure Boundary	Steel	Lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.H2.AP-127	3.3-1, 097	A
Piping, piping components	Pressure Boundary	Copper Alloy	Lubricating Oil	Loss of material due to pitting, crevice corrosion, MIC	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.H2.AP-133	3.3-1, 099	A
Piping, piping components	Pressure Boundary	Copper Alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A
Piping elements	Pressure Boundary	Glass	Lubricating Oil	None	None	VII.J.AP-15	3.3-1, 117	A
Piping elements	Pressure Boundary	Glass	Air	None	None	VII.J.AP-48	3.3-1, 117	A
Piping, piping components	Pressure Boundary	Steel	Air - indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	A
Piping, piping components, tanks	Pressure Boundary	Aluminum	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.H2.A-763a	3.3-1, 234	A

Table 3.3.2-32, Diesel Generator Starting Air System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Air-dry	Loss of material due to general (steel only), pitting, crevice corrosion	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3-1, 235	A

Table 3.3.2-32 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-33, Cranes and Hoists - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Cranes: bridges, structural members, structural components	Structural Support	Steel	Air	Cumulative fatigue damage due to fatigue	Section 4.7, "Other Plant-Specific Analyses"	VII.B.A-06	3.3-1, 001	A
Cranes: rails, bridges, structural members, structural components	Structural Support	Steel	Air	Loss of material due to general corrosion, wear, deformation, cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-07	3.3-1, 052	A
Cranes: structural bolting	Structural Support	High-strength steel	Air	Loss of preload due to self-loosening; loss of material due to general corrosion; cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-730	3.3-1, 199	F, 1
Cranes: structural bolting	Structural Support	Stainless Steel	Air	Loss of preload due to self-loosening; loss of material due to general corrosion; cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-730	3.3-1, 199	F, 1
Cranes: structural bolting	Structural Support	Steel	Air	Loss of preload due to self-loosening; loss of material due to general corrosion; cracking	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.13)	VII.B.A-730	3.3-1, 199	A

Table 3.3.2-33 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. The AMP Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program (B.2.1.13) is used to manage the aging effect(s) applicable to this component type, material and environment combination.

Table 3.3.2-34, Sewage System - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Load Shed Relay (Active)	Not Applicable	Not Applicable	Not Applicable	None	None	None	None	1

Table 3.3.2-34 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.

B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.

C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.

D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.

F. Material not in NUREG-2191 for this component.

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.

Plant Specific Notes

1. Sewage System components are designed and required to load shed in order to meet NFPA 805 performance criteria.

Table 3.3.2-35, FLEX System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Steel	Air - outdoor	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
External surfaces	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.C1.AP-209a	3.3-1, 004	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.C1.AP-221a	3.3-1, 006	A
Piping, piping components	Pressure Boundary	Steel	Raw Water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3-1, 037	A
Piping, piping components	Pressure Boundary	Stainless Steel	Raw Water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3-1, 040	A
Piping, piping components, heat exchanger components (for components not covered by NRC GL 89-13)	Pressure Boundary	Steel	Raw water	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-727	3.3-1, 134	A

Table 3.3.2-35 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-36, Security System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Card Reader (Active)	Not Applicable	Not Applicable	Not Applicable	None	None	None	None	1
Magnetic Lock (Active)	Not Applicable	Not Applicable	Not Applicable	None	None	None	None	1

Table 3.3.2-36 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.

B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.

C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.

D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.

F. Material not in NUREG-2191 for this component.

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.

Plant Specific Notes

1. The Security System card readers and magnetic locks are active components, which facilitate access to locations for credited operator recovery actions.

Table 3.3.2-37, Radiation Monitoring System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VII.I.A-04	3.3-1, 010	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Stainless Steel	Air - indoor uncontrolled	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Closure bolting	Mechanical Closure	Stainless Steel	Air	Cracking due to SSC	Bolting Integrity (B.2.1.10)	VII.I.A-426	3.3-1, 145	A
Piping, piping components	Pressure Boundary	Steel	Air	Cumulative fatigue damage due to fatigue	Section 4.3, “Metal Fatigue”	VII.E3.A-34	3.3-1, 002	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.F3.AP-209a	3.3-1, 004	A
Piping, piping components	Pressure Boundary	Stainless steel	Air, condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VII.F2.AP-221a	3.3-1, 006	A
Piping, piping components	Pressure Boundary	Copper alloy	Raw water	Loss of material due to general, pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3-1, 034	A
Piping, piping components	Pressure Boundary	Stainless steel	Raw water	Loss of material due to pitting, crevice corrosion, MIC; flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-55	3.3-1, 040	A
Piping, piping components	Pressure Boundary	Stainless steel	Closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-186	3.3-1, 043	A

Table 3.3.2-37, Radiation Monitoring System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless steel	Closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3-1, 049	A
Piping, piping components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.A4.AP-32	3.3-1, 072	A
Piping, piping components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Raw water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VII.C1.A-47	3.3-1, 072	A
Piping, piping components	Pressure Boundary	Copper Alloy	Air, condensation	None	None	VII.J.AP-144	3.3-1, 114	A
Piping elements	Pressure Boundary	Glass	Air	None	None	VII.J.AP-48	3.3-1, 117	A
Piping elements	Pressure Boundary	Glass	Raw water	None	None	VII.J.AP-50	3.3-1, 117	A
Piping elements	Pressure Boundary	Glass	Treated water	None	None	VII.J.AP-51	3.3-1, 117	A
Piping elements	Pressure Boundary	Glass	Gas	None	None	VII.J.AP-98	3.3-1, 117	A
Piping, piping components	Pressure Boundary	Steel	Air- indoor controlled	None	None	VII.J.AP-2	3.3-1, 121	A
Piping, piping components	Pressure Boundary	Steel	Gas	None	None	VII.J.AP-6	3.3-1, 121	A
Piping, piping components, heat exchanger components	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.F2.A-722	3.3-1, 157	A
Piping, piping components, tanks	Pressure Boundary	Aluminum	Raw water	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VII.C1.A-451a	3.3-1, 189	A

Table 3.3.2-37, Radiation Monitoring System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless steel	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.A4.AP-110	3.3-1, 203	A
Piping, piping components, tanks	Pressure Boundary	Aluminum	Air, condensation	Loss of material due to pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.A4.A-763c	3.3-1, 234	A
Piping, piping components	Pressure Boundary	Aluminum	Raw water	Flow blockage due to fouling	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-793a	3.3-1, 259	A
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Polymeric	Air	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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.C1.A-797b	3.3-1, 263	A

Table 3.3.2-37 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.3.2-38, Hardened Containment Venting System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air - outdoor	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VII.I.A-03	3.3-1, 012	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Closure bolting	Mechanical Closure	Steel	Air - outdoor	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Closure bolting	Mechanical	Steel	Underground	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VII.I.AP-124	3.3-1, 015	A
Closure bolting	Mechanical Closure	Steel	Underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-241	3.3-1, 109	A
External surfaces	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3-1, 078	A
Piping, piping components	Pressure Boundary	Steel	Underground	Loss of material due to general, pitting, crevice corrosion	Buried and Underground Piping and Tanks (B.2.1.27)	VII.I.AP-284	3.3-1, 109	A

Table 3.3.2-38 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

3.4 AGING MANAGEMENT OF STEAM AND POWER CONVERSION SYSTEMS

3.4.1 Introduction

This section provides the results of the 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.

- Main Steam System (2.3.4.1)
- Condensate/Demineralized Water System (2.3.4.2)
- Reactor Feedwater System (2.3.4.3)
- Heater Drains and Vents System (2.3.4.4)
- Miscellaneous Turbine Connections System (2.3.4.5)
- Condenser Circulating Water System (2.3.4.6)
- Gland Seal Water System (2.3.4.7)

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, Main Steam System - Summary of Aging Management Evaluation
- Table 3.4.2-2, Condensate/Demineralized Water System - Summary of Aging Management Evaluation
- Table 3.4.2-3, Reactor Feedwater System - Summary of Aging Management Evaluation
- Table 3.4.2-4, Heater Drains and Vents System - Summary of Aging Management Evaluation
- Table 3.4.2-5, Miscellaneous Turbine Connections System - Summary of Aging Management Evaluation
- Table 3.4.2-6, Condenser Circulating System - Summary of Aging Management Evaluation
- Table 3.4.2-7, Gland Seal Water System - Summary of Aging Management Evaluation

3.4.2.1 Materials, Environments, Aging Effects Requiring Management And Aging Management Programs

3.4.2.1.1 Main Steam System

Materials

The materials of construction for the Main Steam System components are:

- Aluminum
- Any
- Cast Austenitic Stainless Steel (CASS)
- High-strength steel
- Stainless Steel
- Steel

Environments

The Main Steam System components are exposed to the following environments:

- Air
- Air - dry
- Air - indoor uncontrolled
- Air - outdoor
- Any
- Reactor coolant
- Reactor coolant >250°C (>482°F)
- Steam
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the Main Steam System components require management:

- Cracking
- Cumulative Fatigue Damage
- Loss of Fracture Toughness
- 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 components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD (B.2.1.1)
- Water Chemistry (B.2.1.2)
- BWR Stress Corrosion Cracking (B.2.1.5)
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B.2.1.8)
- Flow-Accelerated Corrosion (B.2.1.9)
- Bolting Integrity (B.2.1.10)
- Compressed Air Monitoring (B.2.1.14)
- One-Time Inspection (B.2.1.20)
- ASME Code Class 1 Small-Bore Piping (B.2.1.22)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- TLAA (Section 4.3)

3.4.2.1.2 Condensate/Demineralized Water System

Materials

The materials of construction for the Condensate/Demineralized Water System components are:

- Aluminum
- Any
- Cast Iron and Cast Iron Alloy
- Copper alloy
- Copper alloy (>15% Zn or >8% Al)
- Ductile iron
- Gray cast iron
- High-strength steel
- Metallic
- Polymeric
- PVC
- Stainless Steel
- Steel

Environments

The Condensate/Demineralized Water System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air - outdoor
- Any
- Concrete
- Lubricating oil
- Raw water
- Steam
- Treated water
- Treated water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects associated with the Condensate/Demineralized Water System components require management:

- Cracking
- Hardening or Loss of Strength
- 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 Condensate/ Demineralized Water System components:

- Water Chemistry (B.2.1.2)
- Flow-Accelerated Corrosion (B.2.1.9)
- Bolting Integrity (B.2.1.10)
- Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.17)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Lubricating Oil Analysis (B.2.1.25)
- Buried and Underground Piping and Tanks (B.2.1.27)
- Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)

3.4.2.1.3 Reactor Feedwater System

Materials

The materials of construction for the Reactor Feedwater System components are:

- Any
- Cast austenitic stainless steel (CASS)
- Copper alloy
- Copper alloy (>15% Zn or >8% Al)
- High-strength steel
- Nickel alloy
- Stainless steel
- Steel

Environments

The Reactor Feedwater System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air - outdoor
- Any
- Reactor coolant
- Reactor coolant >250°C (>482°F)

- Treated water
- Treated water >60°C (>140°F)

Aging Effects Requiring Management

The following aging effects associated with the Reactor Feedwater System components require management:

- Cracking
- Cumulative Fatigue Damage
- Loss of Fracture Toughness
- 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 Reactor Feedwater System components:

- ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD (B.2.1.1)
- Water Chemistry (B.2.1.2)
- BWR Stress Corrosion Cracking (B.2.1.5)
- Flow-Accelerated Corrosion (B.2.1.9)
- Bolting Integrity (B.2.1.10)
- One-Time Inspection (B.2.1.20)
- ASME Code Class 1 Small-Bore Piping (B.2.1.22)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- TLAA (Section 4.3)

3.4.2.1.4 Heater Drains and Vents System

Materials

The materials of construction for the Heater Drains and Vents System components are:

- Any
- Cast Iron
- Stainless steel
- Steel

Environments

The Heater Drains and Vents System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled

- Any
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the Heater Drains and Vents System components require management:

- 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 Heater Drains and Vents System components:

- Water Chemistry (B.2.1.2)
- Flow-Accelerated Corrosion (B.2.1.9)
- Bolting Integrity (B.2.1.10)
- One-Time Inspection (B.2.1.20)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)

3.4.2.1.5 Miscellaneous Turbine Connections System

Materials

The materials of construction for the Miscellaneous Turbine Connections System components are:

- Steel

Environments

The Miscellaneous Turbine Connections System components are exposed to the following environments:

- Air - indoor uncontrolled
- Any
- Steam
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the Miscellaneous Turbine Connections System components require management:

- Loss of Material
- Loss of Preload
- Wall Thinning

Aging Management Programs

The following aging management programs manage the aging effects for the Miscellaneous Turbine Connections System components:

- Water Chemistry (B.2.1.2)
- Flow-Accelerated Corrosion (B.2.1.9)
- Bolting Integrity (B.2.1.10)
- One-Time Inspection (B.2.1.20)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)

3.4.2.1.6 Condenser Circulating System

Materials

The materials of construction for the Condenser Circulating System components are:

- Cast Iron and Cast Iron Alloy
- Copper alloy
- Stainless steel
- Steel

Environments

The Condenser Circulating System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air - outdoor
- Any
- Concrete
- Condensation
- Raw water
- Soil

Aging Effects Requiring Management

The following aging effects associated with the Condenser Circulating System components require management:

- Cracking
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Condenser Circulating System components:

- Bolting Integrity (B.2.1.10)
- One-Time Inspection (B.2.1.20)

- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)
- Buried and Underground Piping and Tanks (B.2.1.27)

3.4.2.1.7 Gland Seal Water System

Materials

The materials of construction for the Gland Seal Water System components are:

- Cast Iron and Cast Iron Alloy
- Copper alloy
- Copper alloy (>15% Zn or >8% Al)
- Glass
- Gray cast iron
- Steel

Environments

The Gland Seal Water System components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air - outdoor
- Any
- Treated water

Aging Effects Requiring Management

The following aging effects associated with the Gland Seal Water System components require management:

- Cracking
- Loss of Material
- Loss of Preload

Aging Management Programs

The following aging management programs manage the aging effects for the Gland Seal Water System components:

- Water Chemistry (B.2.1.2)
- Bolting Integrity (B.2.1.10)
- One-Time Inspection (B.2.1.20)
- Selective Leaching (B.2.1.21)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)

3.4.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL-SLR Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the subsequent license renewal application. For the Steam and Power Conversion Systems, those programs are addressed in the following subsections.

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 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.

<u>Table 3.4.1 Item Number 3.4-1, 001:</u> This item evaluates steel piping, piping components exposed to any environment for cumulative fatigue damage due to fatigue. Cumulative fatigue damage of steel piping, piping components is evaluated and dispositioned as a TLAA for the Main Steam System, Condensate/Demineralized Water System and Reactor Feedwater System as discussed in Section 4.3.

3.4.2.2.2 Cracking Due to Stress Corrosion Cracking in Stainless Steel Alloys

Cracking due to stress corrosion cracking (SCC) could occur in indoor or outdoor stainless steel (SS) piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components, or (d) in the vicinity of potentially transportable halogens. Cracking can occur in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS components exposed to indoor air, outdoor air, condensation, or underground environments are susceptible to SCC if the insulation contains certain contaminants. Leakage of fluids through bolted connections (e.g., flanges, valve packing) can result in contaminants present in the insulation leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS components, rain and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific operating experience (OE) and the condition of SS components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in SCC. SCC in SS components is not an aging effect requiring management if (a) plant-specific OE does not reveal a history of SCC and (b) a one-time inspection demonstrates that the aging effect is not occurring.

In the environment of air-indoor controlled, SCC is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations. The applicant documents the results of the plant-specific OE review in the SLRA.

The GALL-SLR Report recommends further evaluation of SS piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of SCC. The GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that SCC is not occurring. If SCC is occurring, the following AMPs describe acceptable programs to manage loss *of material due to SCC: (a) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.*

The applicant may establish that SCC is not an aging effect requiring management for all components, by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.

<u>Table 3.4.1 Item Number 3.4-1, 002:</u> This item evaluates cracking due to SCC in stainless steel piping, piping components, and tanks exposed to air and condensation environments. There is only one stainless steel tank in the screened-in portions of the Steam and Power Conversion Systems, the Condensate Head Drain Tank. There are no stainless steel piping, piping components exposed to the air-indoor controlled environment in the screened-in portions of the Steam and Power Conversion Systems. Stainless steel components within the screened-in portions of the Steam and Power Conversion Systems are located in the following systems: Main Steam, Condensate/Demineralized Water, Reactor Feedwater, and Condenser Circulating Water. Plant-specific OE associated with stainless steel components in the screened-in portions of the Steam and Power Conversion Systems has been evaluated to determine if prolonged exposure to the air-indoor uncontrolled, air-outdoor, and condensation environments has resulted in cracking due to SCC. Cracking has not been identified as an aging effect at BFN for stainless steel screened-in components in these environments. Cracking has been identified as an aging effect at BFN for stainless steel components as a result of transportable halogens, indicating that the environments do contain sufficient halides (e.g., chlorides) in the presence of moisture to result in SCC (for the sample probes exposed to treated water) as described below.

- On May 25, 2023, a component failure of a sample probe upstream of the condensate booster pump was documented in a CR, where the failure has been attributed to SCC in stainless steel. This component (sample probe upstream of the Condensate Booster Pump) is screened-in for SLR.
- The component that failed was an original design sample probe. The sample probe which failed was located in the Condensate/Demineralized Water System piping upstream of the Reactor Feedwater Pumps. A total of 3 Condensate/Demineralized Water System sample probes are installed in the three BFN units (1 per unit). Each one of these three components will be permanently removed from the system prior to the subsequent period of extended operation.
- The CR extent of condition evaluation determined that the reported condition also applied to the sample probes in the Feedwater System. A total of 12 Feedwater sample probes are installed in the three BFN units (4 per unit). All of these components have been confirmed to have been replaced with an upgraded design, except for three of the four

Feedwater sample probes in Unit 2. These three BFN Unit 2 Feedwater System sample probes will be inspected to ensure the design is consistent with the upgraded design for these sample probes. If any of these probes cannot be confirmed as being consistent with the upgraded design, the probe(s) will be replaced with upgraded design sample probes prior to entry into the subsequent period of extended operation.

- A review of BFN-specific OE shows that BFN has not experienced any failures of the upgraded design sample probes. Therefore, the upgraded design Feedwater sample probes are included in the population of stainless steel piping and piping components with the potential to experience stress corrosion cracking (SCC) and will be managed by the One-Time Inspection program (B.2.1.20) to demonstrate that stainless steel SCC is not occurring and by the Water Chemistry program (B.2.1.2) to maintain reactor water chemistry parameters within acceptance limits.

Accordingly, the One-Time Inspection program (B.2.1.20) will be implemented to demonstrate the aging effect of cracking in stainless steel piping, piping components exposed to air-indoor uncontrolled, air-outdoor, and condensation is not occurring. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection program (B.2.1.20) is described in Appendix B.

Table 3.4.1 Item Number 3.4-1, 074: This item evaluates cracking due to SCC of stainless steel piping, piping components and tanks located in an underground environment. This item is restricted to only underground environments. There are no stainless steel underground piping, piping components or tanks in screened-in portions of the Steam and Power Conversion System.

Table 3.4.1 Item Number 3.4-1, 100: Not applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to air or condensation within the screened-in portions of the Steam and Power Conversion Systems.

Table 3.4.1 Item Number 3.4-1, 104: This item evaluates cracking due to SCC in insulated stainless steel piping, piping components, and tanks exposed to air and condensation environments. There are no insulated stainless steel tanks in the screened-in portions of the Steam and Power Conversion Systems. There are no insulated stainless steel piping or piping components exposed to the air-indoor controlled environment. The remaining components to be evaluated are insulated stainless steel piping and piping components exposed to air-indoor uncontrolled, air-outdoor, or condensation environments in the screened-in portions of the Steam and Power Conversion Systems. Insulated stainless steel piping and piping components within the screened-in portions of the Steam and Power Conversion Systems are located in the following systems: Main Steam, Condensate/Demineralized Water, and Reactor Feedwater. Plant-specific OE associated with insulated stainless steel piping and piping components exposed to air-indoor uncontrolled, air-outdoor, or condensation environments in the screened-in portions of the Steam and Power Conversion Systems has been evaluated to determine if prolonged exposure to these environments has resulted in cracking due to SCC. Cracking has not been identified as an aging effect at BFN for insulated stainless steel components in the air-indoor uncontrolled, air-outdoor, or condensation environments indicating that moisture intrusion into the insulation and leaching of contaminants present in the insulation onto component surfaces, or onto other components below the insulated component, resulting in SCC, has not occurred. Accordingly, the One-Time Inspection program (B.2.1.20) will be used to demonstrate that the cracking aging effect is not occurring in screened-in insulated stainless steel piping and piping components exposed to air-indoor uncontrolled, air-outdoor or condensation environments in the screened-in portions of the Steam and Power Conversion

Systems. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection program (B.2.1.20) is described in Appendix B.

3.4.2.2.3 Loss of Material Due to Pitting and Crevice Corrosion in Stainless Steel and Nickel Alloys

Loss of material due to pitting and crevice corrosion could occur in indoor or outdoor SS and nickel alloy piping, piping components, and tanks exposed to any air, condensation, or underground environment when the component is: (a) uninsulated; (b) insulated; (c) in the vicinity of insulated components; or (d) in the vicinity of potentially transportable halogens. Loss of material due to pitting and crevice corrosion can occur on SS and nickel alloys in environments containing sufficient halides (e.g., chlorides) in the presence of moisture.

Insulated SS and nickel alloy components exposed to air, condensation, or underground environments are susceptible to loss of material due to pitting or crevice corrosion if the insulation contains certain contaminants. Leakage of fluids through mechanical connections such as bolted flanges and valve packing can result in contaminants leaching onto the component surface or the surfaces of other components below the component. For outdoor insulated SS and nickel alloy components, rain, and changing weather conditions can result in moisture intrusion into the insulation.

Plant-specific OE and the condition of SS and nickel alloy components are evaluated to determine if prolonged exposure to the plant-specific environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for SS and nickel alloy components if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion; and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Inspections focus on the most susceptible locations.

The GALL-SLR Report recommends further evaluation of SS and nickel alloy piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One- Time Inspection," describes an acceptable program to demonstrate that loss of material due to pitting and crevice corrosion is not occurring at a rate that affects the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting or crevice corrosion: (a) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (b) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (c) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (d) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant *during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.*

The applicant may establish that loss of material due to pitting and crevice corrosion is not an aging effect requiring management by demonstrating that a barrier coating isolates the component from aggressive environments. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating.

<u>Table 3.4.1 Item Number 3.4-1, 003:</u> This item evaluates loss of material due to pitting and crevice corrosion in stainless steel and nickel alloy piping, piping components, and tanks exposed to air or condensation environments. There is one stainless steel tank, the Condensate Head Drain Tank, in the screened-in portion of the Steam and Power Conversion Systems. There are no nickel alloy tanks, or nickel alloy piping, piping components in the screened-in portions of the Steam and Power Conversion Systems. There are no stainless steel piping, piping components exposed to air-indoor controlled in the screened-in portions of the Steam and Power Conversion Systems. Stainless steel or nickel alloy components with the passive function Pressure Boundary within the screened-in portions of the Steam and Power Conversion Systems are located in the following systems: Main Steam, Condensate/Demineralized Water, Reactor Feedwater, and Condenser Circulating Water. Plant-specific operating experience (OE) associated with stainless steel components in the screened-in portions of the Steam and Power Conversion Systems has been evaluated to determine if prolonged exposure to air-indoor uncontrolled, air-outdoor, and condensation environments has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect in the screened-in portions of the Steam and Power Conversion Systems at BFN for stainless steel components in these environments, or as a result of transportable halogens, indicating that these environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in loss of material. Accordingly, the One-Time Inspection program (B.2.1.20) will be implemented to demonstrate that the aging effect of loss of material is not occurring in stainless steel piping, piping components exposed to air-indoor uncontrolled, air-outdoor, and condensation. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection program (B.2.1.20) is described in Appendix B.

<u>Table 3.4.1 Item Number 3.4-1, 095:</u> This item evaluates loss of material due to pitting, crevice corrosion of stainless steel and nickel alloy piping, piping components and tanks located in an underground environment. This item is restricted to only underground environments. There are no stainless steel and nickel alloy underground piping, piping components, or tanks within the screened-in portions of the Steam and Power Conversion Systems.

<u>Table 3.4.1 Item Number 3.4-1, 098:</u> Not applicable. There are no stainless steel or nickel alloy tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") in the screened-in portions of the Steam and Power Conversion Systems.

<u>Table 3.4.1 Item Number 3.4-1, 103:</u> This item evaluates loss of material due to pitting and crevice corrosion in insulated stainless steel or nickel alloy piping, piping components, and tanks exposed to air and condensation environments. There is one stainless steel tank, the Condensate Head Drain Tank, in the screened-in portion of the Steam and Power Conversion

Systems, however, this tank is not insulated. There are no insulated stainless steel or nickel alloy piping or piping components exposed to the air-indoor controlled environment in the screened-in portions of the Steam and Power Conversion Systems. Additionally, there are no insulated nickel alloy piping, piping components in the screened-in portions of the Steam and Power Conversion Systems. The remaining components to be evaluated are insulated stainless steel piping and piping components exposed to air-indoor uncontrolled, air-outdoor, or condensation environments within the screened-in portions of the Steam and Power Conversion Systems. Stainless steel or nickel alloy piping, piping components and tanks within the screened-in portions of the Steam and Power Conversion Systems are located in the following systems: Main Steam, Condensate/Demineralized Water, Reactor Feedwater, and Condenser Circulating Water. However, these components in the Condenser Circulating Water System are not insulated. Plant-specific OE associated with insulated stainless steel components in the screened-in portions of the Steam and Power Conversion Systems has been evaluated to determine if prolonged exposure to air-indoor uncontrolled, air-outdoor, or condensation environments has resulted in loss of material due to pitting or crevice corrosion. Loss of material has not been identified as an aging effect at BFN for screened-in insulated stainless steel components in these environments, indicating that moisture intrusion into the insulation and leaching of contaminants present in the insulation onto component surfaces, or onto other components below the insulated component, resulting in loss of material, has not occurred. Accordingly, the One-Time Inspection program (B.2.1.20) will be used to demonstrate that the aging effect of loss of material due to pitting or crevice corrosion is not occurring in insulated stainless steel piping and piping components exposed to air-indoor uncontrolled, air-outdoor, or condensation environments in the screened-in portions of the Steam and Power Conversion Systems. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection program (B.2.1.20) is described in Appendix B.

3.4.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

QA provisions applicable to Subsequent License Renewal are discussed in Appendix A, Section A.1.4, and Appendix B, Section B.1.3.

3.4.2.2.5 Ongoing Review of Operating Experience

Ongoing review of operating experience is addressed in Appendix A, Section A.1.5, and Appendix B, Section B.1.4.

3.4.2.2.6 Loss of Material Due to Recurring Internal Corrosion

Recurring internal corrosion can result in the need to augment AMPs beyond the recommendations in the GALL-SLR Report. During the search of plant-specific OE conducted during the SLRA development, recurring internal corrosion can be identified by the number of occurrences of aging effects and the extent of degradation at each localized corrosion site. This further evaluation item is applicable if the search of plant specific OE reveals repetitive occurrences. The criteria for recurrence is (a) a 10 year search of plant specific OE reveals the aging effect has occurred in three or more refueling outage cycles; or (b) a 5 year search of plant specific OE reveals the aging effect has occurred in two or more refueling outage cycles and resulted in the component either not meeting plant specific acceptance criteria or experiencing a reduction in wall thickness greater than 50 percent (regardless of the minimum wall thickness).

The GALL-SLR Report recommends that GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," be evaluated for inclusion of augmented requirements to ensure the adequate management of any recurring aging effect(s). Alternatively, a plant-specific AMP may be proposed. Potential augmented requirements include: (i) alternative examination methods (e.g., volumetric versus external visual); (ii) augmented inspections (e.g., a greater number of locations, additional locations based on risk insights based on susceptibility to aging effect and consequences of failure, a greater frequency of inspections), and (iii) additional trending parameters and decision points where increased inspections would be implemented.

The applicant states: (a) why the program's examination methods will be sufficient to detect the recurring aging effect before affecting the ability of a component to perform its intended function, (b) the basis for the adequacy of augmented or lack of augmented inspections, (c) what parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., the extent of degradation at individual corrosion sites, the rate of degradation change), (d) how inspections of components that are not easily accessed (i.e., buried, underground) will be conducted, and (e) how leaks in any involved buried or underground components will be identified.

Plant-specific OE examples should be evaluated to determine if the chosen AMP should be augmented even if the thresholds for significance of aging effect or frequency of occurrence of aging effect have not been exceeded. For example, during a 10 year search of plant-specific OE, two instances of a 360 degree 30 percent wall loss occurred at copper alloy to steel joints. Neither the significance of the aging effect nor the frequency of occurrence of aging effect threshold has been exceeded. Nevertheless, the OE should be evaluated to determine if the AMP that is proposed to manage the aging effect is sufficient (e.g., method of inspection, frequency of inspection, number of inspections) to provide reasonable assurance that the current licensing basis (CLB) intended functions of the component will be met throughout the subsequent period of extended operation. While recurring internal corrosion is not as likely in other environments as raw water and waste water (e.g., treated water), the aging effect should be addressed in a similar manner.

<u>Table 3.4.1 Item Number 3.4-1, 061:</u> Not Applicable. This item evaluates loss of material due to recurring internal corrosion of metallic piping, piping components, and tanks exposed to raw water and waste water. There are no components exposed to waste water in the screened-in portions of the Steam and Power Conversion Systems. The Condenser Circulating Water System is the only Steam and Power Conversion System where the components are exposed to raw water. Plant-specific OE associated with loss of material of metallic components in the Steam and Power Conversion Systems has been evaluated over the period from 2011 to 2022 to identify instances of loss of material due to recurring internal corrosion in raw water and other internal environments. The OE review did not identify any components within the Steam and Power Conversion Systems where the frequency and severity for loss of material met the thresholds discussed above that would require augmenting the aging management recommendations in the GALL-SLR Report to manage loss of material due to recurring internal corrosion.

3.4.2.2.7 Cracking Due to Stress Corrosion Cracking in Aluminum Alloys

SCC is a form of environmentally assisted cracking which is known to occur in high and moderate strength aluminum alloys. The three conditions necessary for SCC to occur in a component are a sustained tensile stress, aggressive environment, and material with a *susceptible microstructure. Cracking due to SCC can be mitigated by eliminating one of the three necessary conditions. For the purposes of SLR, acceptance criteria for this further evaluation is being provided for demonstrating that the specific material is not susceptible to SCC or an aggressive environment is not present. Cracking due to SCC is an aging effect requiring management unless it is demonstrated by the applicant that one of the two necessary conditions discussed below is absent.*

<u>Susceptible Material:</u> 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.

<u>Aggressive Environment:</u> If the environment to which an aluminum alloy is exposed is not aggressive, such as dry gas or treated water, then cracking due to SCC will not occur and it is not an aging effect requiring management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys are aqueous solutions, air, condensation, and underground locations that contain halides (e.g., chloride). Halide concentrations should be considered high enough to facilitate SCC of aluminum alloys in uncontrolled or untreated aqueous solutions and air, such as raw water, waste water, condensation, underground locations, and outdoor air, unless demonstrated otherwise.

Halides could be present on the surface of the aluminum material if the component is encapsulated in a material such as insulation or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, sufficient halide concentrations to cause SCC could be present due to secondary sources such as leakage from nearby components (e.g., leakage from insulated flanged connections or valve packing). If an aluminum component is exposed to a halide-free indoor air environment, not encapsulated in materials containing halides, and the exposure to secondary sources of moisture or halides is precluded, cracking due *to SCC is not expected to occur. The plant-specific configuration can be used to demonstrate that exposure to halides will not occur. If it is determined that SCC will not occur because the environment is not aggressive, the SLRA provides the components and locations exposed to the environment, description of the environment, basis used to determine the environment is not aggressive, and technical information substantiating the basis. GALL-SLR Report AMP XI.M32, "One-Time Inspection," and a review of plant-specific OE describe an acceptable means to confirm the absence of moisture or halides within the proximity of the aluminum component.*

If the environment potentially contains halides, GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," describes an acceptable program to manage cracking due to SCC of aluminum tanks. GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking due to SCC of aluminum piping and piping components. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage cracking due to SCC of aluminum piping and tanks which are buried or underground. GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," describes an acceptable program to manage cracking due to SCC of aluminum components that are not included in other AMPs.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent SCC. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

Table 3.4.1 Item Number 3.4-1, 102: Not applicable. There are no 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 within the screened-in portions of the Steam and Power Conversion Systems.

Table 3.4.1 Item Number 3.4-1, 105: This item evaluates cracking due to SCC in insulated aluminum piping, piping components, and tanks exposed to air and condensation environments. There are no insulated aluminum piping and piping components exposed to an air-indoor controlled environment in the screened-in portions of the Steam and Power Conversion Systems. The aluminum tanks, the Condensate Head Tank and the Demineralized Water Tanks, in the screened-in portions of the Steam and Power Conversion Systems are not insulated. This leaves insulated aluminum piping and piping components exposed to air-indoor uncontrolled, air-outdoor and condensation environments in the screened-in portion of the Steam and Power Conversion Systems needing evaluation. Insulated aluminum piping and piping components with the passive function Pressure Boundary and within the screened-in portions of the Steam and Power Conversion Systems are located in the following systems: Condensate/Demineralized Water. Plant-specific OE associated with insulated aluminum components in the screened-in portions of the Steam and Power Conversion Systems has been evaluated to determine if prolonged exposure to the air-indoor uncontrolled, air-outdoor, and condensation environments has resulted in cracking due to SCC. Cracking has not been identified as an aging effect at BFN for insulated aluminum screened-in components in these environments. Cracking has not been identified as an aging effect at BFN for screened-in insulated aluminum components as a result of transportable halogens, indicating that the environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in SCC. Accordingly, the One-Time Inspection program (B.2.1.20) will be used to demonstrate that the aging effect of cracking due to SCC is not occurring in insulated aluminum piping and piping components exposed to air-indoor uncontrolled, air- outdoor, or condensation environments. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection program (B.2.1.20) is described in Appendix B.

Table 3.4.1 Item Number 3.4-1, 109: This item evaluates cracking due to SCC in aluminum piping, piping components, and tanks exposed to air, condensation, raw water, and waste water environments. The aluminum tanks, the Condensate Head Tank and the Demineralized Water Tanks, in the screened-in portions of the Steam and Power Conversion Systems are exposed to air and condensation environments, but are not exposed to raw water or waste water environments. There are no aluminum piping, piping components or tanks exposed to the air-indoor controlled, raw water, or waste water environments in the screened-in portions of the Steam and Power Conversion Systems. This leaves aluminum piping, piping components and tanks exposed to air-indoor uncontrolled, air-outdoor, and condensation in the screened-in portions of the Steam and Power Conversion Systems to be evaluated. Aluminum piping, piping components, tanks within the screened-in portions of the Steam and Power Conversion Systems are located in the following systems: Main Steam, and Condensate/Demineralized Water. Plant-specific OE associated with aluminum components in the screened-in portions of the Steam and Power Conversion Systems has been evaluated to determine if prolonged exposure to the air-indoor uncontrolled, air-outdoor, and condensation environments has resulted in cracking due to SCC. Cracking due to SCC has not been identified as an aging effect at BFN for aluminum components located in the Condensate/Demineralized Water System in these environments. Additionally, because cracking due to SCC has not been identified as an aging effect at BFN for aluminum components located in the Condensate/Demineralized Water System in these environments, cracking due to SCC resulting from transportable halogens, has not been identified, indicating that these environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in SCC. Accordingly, the One-Time Inspection program (B.2.1.20) will be used to demonstrate the aging effect of cracking due to SCC in aluminum piping, piping components and tanks exposed to air-indoor uncontrolled, air-outdoor, and condensation environments within the screened-in portions of the Steam and Power Conversion Systems is not occurring. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection program (B.2.1.20) is described in Appendix B.

Table 3.4.1 Item Number 3.4-1, 112: This item evaluates cracking due to SCC of aluminum piping, piping components and tanks located in an underground environment. This item is restricted to only underground environments. There are no aluminum underground piping, piping components, or tanks within the screened-in portions of 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.

Table 3.4.1 Item Number 3.4-1, 051: Consistent with NUREG-2191. This item evaluates loss of material due to general, crevice or pitting corrosion of steel piping and piping components exposed to a concrete environment. For the screened-in portions of the BFN Steam and Power Conversion System, loss of material due to general, crevice or pitting corrosion of steel piping and piping components is not an applicable aging effect because the exclusion criteria are met. The same concrete specification was used for all structures at BFN. The original designs and construction of these structures conformed to ACI 318 (1963 and later revisions as noted in FSAR Section 12.2) and ACI 307 (as referenced in FSAR Section 12.2 and the constructions specifications) except as noted. The concrete mix designs provide for low permeability by incorporating fly ash and water reducing agents. Concrete fine and course aggregates conform to ASTM C33. The cement is primarily Type II Portland cement with small scale concrete being Type I Portland cement. The Portland cement conforms to ASTM C-150. A site-specific OE review was performed and it was determined that BFN has not found any evidence of concrete degradation that could lead to penetration of water to the metal surface. Furthermore, the steel piping that is screened-in for SLR and exposed to concrete is not potentially exposed to groundwater.

Table 3.4.1 Item Number 3.4-1, 082: Consistent with NUREG-2191. This item evaluates stainless steel piping and piping components exposed to a concrete environment. The combination of stainless steel piping and piping components and a concrete environment exists in the screened-in portions of the following Steam and Power Conversion Systems: Condensate/ Demineralized Water System. Loss of material and cracking due to SCC are not considered to be applicable aging effects for portions of the stainless steel piping and piping components exposed to concrete that is indoors, or outdoors and above ground level, in the screened-in portions of the Condensate/Demineralized Water System because the piping is not potentially exposed to groundwater. Therefore, loss of material and cracking due to SCC are not considered to be applicable aging effects for the screened-in portions of the Condensate/Demineralized

Water System because there are no stainless steel piping and piping components that are exposed to concrete, and are outdoors and below ground level.

3.4.2.2.9 Loss of Material Due to Pitting and Crevice Corrosion in Aluminum Alloys

Loss of material due to pitting and crevice corrosion could occur in aluminum piping, piping components, and tanks exposed to an air, condensation, underground, raw water, or waste water environment for a sufficient duration of time. Environments that can result in pitting and/or crevice corrosion of aluminum alloys are those that contain halides (e.g., chloride) in the presence of moisture. The moisture level and halide concentration in atmospheric and uncontrolled air are greatly dependent on geographical location and site-specific conditions. Moisture level and halide concentration should be considered high enough to facilitate pitting and/or crevice corrosion of aluminum alloys in atmospheric and uncontrolled air, unless demonstrated otherwise. The periodic introduction of moisture or halides into an environment from secondary sources should also be considered. Leakage of fluids from mechanical connections (e.g., insulated bolted flanges and valve packing); onto a component in indoor controlled air is an example of a secondary source that should be considered. Halide concentrations should be considered high enough to facilitate loss of material of aluminum alloys in untreated aqueous solutions, unless demonstrated otherwise. Plant-specific OE and the condition of aluminum alloy components are evaluated to determine if prolonged exposure to the plant-specific air, condensation, underground, or water environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for aluminum alloys if (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components. The applicant documents the results of the plant-specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Alloy susceptibility may be considered when reviewing OE and interpreting inspection results. Inspections focus on the most susceptible alloys and locations.

The GALL-SLR Report recommends the further evaluation of aluminum piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time Inspection," describes an acceptable program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting and crevice corrosion: (i) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (ii) GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (iii) GALL-SLR Report AMP XI.M41,"Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (iv) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" for internal surfaces of components that are not included in other AMPs. The timing of the one-time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one-time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent loss of material due to pitting and crevice corrosion. Acceptable barriers include tightly-adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," or equivalent program, describes an acceptable program to manage the integrity of a barrier coating.

<u>Table 3.4.1 Item Numbers 3.4-1, 035:</u> This item evaluates loss of material due to pitting and crevice corrosion in aluminum piping, piping components, and tanks exposed to air or condensation environments, and not located in an underground environment. There are aluminum tanks, the Condensate Head Tank and the Demineralized Water Tanks, in the screened-in portions of the Steam and Power Conversion Systems exposed to air, condensation. Additionally, there are aluminum piping or piping components exposed to the air-outdoor, or condensation environments in the screened-in portions of the Steam and Power Conversion Systems. Aluminum components within the screened-in portions of the Steam and Power Conversion Systems are located in the following systems: Main Steam, and Condensate/ Demineralized Water. Plant-specific OE associated with aluminum components in the Steam and Power Conversion Systems has been evaluated to determine if prolonged exposure to the air-indoor uncontrolled environment has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at BFN for aluminum components in this environment. Consequently, loss of material as a result of transportable halogens has not been identified, indicating that these environments do not contain sufficient halides (e.g., chlorides) in the presence of moisture to result in loss of material. Accordingly, the One-Time Inspection program (B.2.1.20) will be implemented to demonstrate the aging effect of loss of material in aluminum piping, piping components exposed to air-indoor uncontrolled is not occurring in the screened-in portions of the Steam and Power Conversion systems. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection program (B.2.1.20) is described in Appendix B.

<u>Table 3.4.1 Item Number 3.4-1, 094:</u> This item evaluates loss of material due to pitting, crevice corrosion of aluminum piping, piping components and tanks located in an underground environment. This item is restricted to only underground environments. There are no aluminum underground piping, piping components, or tanks within the screened-in portions of the Steam and Power Conversion Systems.

<u>Table 3.4.1 Item Number 3.4-1, 097:</u> Not applicable. There are no aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") in the screened-in portions of the Steam and Power Conversion Systems.

<u>Table 3.4.1 Item Number 3.4-1, 119:</u> This item evaluates loss of material due to pitting and crevice corrosion in insulated aluminum piping, piping components, and tanks exposed to air and condensation environments. There are no insulated aluminum piping, piping components, or tanks in the screened-in portions of the Steam and Power Conversion Systems exposed to an air-indoor controlled environment. Aluminum tanks, the Condensate Head Tank and the Demineralized Water Tanks, are exposed to air, and condensation environments in the screened-in portions of the Steam and Power Conversion Systems, however, these tanks are not insulated. This leaves insulated aluminum piping and piping components exposed to air-indoor uncontrolled, air-outdoor, and condensation environments, and not located in an underground environment, needing evaluation. Insulated aluminum components with the passive function Pressure Boundary within the screened-in portions of the Steam and Power Conversion Systems

are located in the following systems: Condensate/Demineralized Water. Plant-specific OE associated with insulated aluminum components in the screened-in portions of the Steam and Power Conversion Systems has been evaluated to determine if prolonged exposure to air-indoor uncontrolled, air-outdoor, or condensation environments has resulted in loss of material due to pitting and crevice corrosion. Loss of material has not been identified as an aging effect at BFN for screened-in insulated aluminum components in these environments, indicating that moisture intrusion into the insulation and leaching of contaminants present in the insulation on to component surfaces, or onto other components below the insulated component, resulting in loss of material, has not occurred. Accordingly, the One-Time Inspection program (B.2.1.20) will be used to demonstrate the aging effect of loss of material from insulated aluminum piping and piping components exposed to air-indoor uncontrolled, air- outdoor, or condensation environments within the screened-in portions of the BFN Steam and Power Conversion Systems is not occurring. Deficiencies will be documented in accordance with 10 CFR Part 50, Appendix B Corrective Action Program. The One-Time Inspection program (B.2.1.20) is described in Appendix B.

Table 3.4.1 Item Number 3.4-1, 120: Not applicable. There are no aluminum piping, piping components, or tanks exposed to raw water or waste water within the screened-in portions of the Steam and Power Conversion Systems. There are aluminum tanks, the Condensate Head Tank and the Demineralized Water Tanks, in the screened-in portions of the Steam and Power Conversion Systems. However, these tanks are exposed to treated water, not raw water, waste water. There are no components exposed to waste water in the screened-in portions of the Steam and Power Conversion Systems. The Condenser Circulating Water System is the only Steam and Power Conversion System where the components are exposed to raw water, however, there are no aluminum piping, piping components, or tanks located in the screened-in portions of the Condenser Circulating Water System.

3.4.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Steam and Power Conversion System components:

- Section 4.3, Metal Fatigue Analyses
  - Section 4.3.2, Metal Fatigue of Class 1 Components
  - Section 4.3.4, Metal Fatigue of Non-Class 1 Components
  - Section 4.3.5, Environmental Fatigue Analyses for Reactor Vessel and Class 1 Piping

3.4.3 Conclusion

The Steam and Power Conversion System components that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Steam and Power Conversion System components are identified in the summaries in Section 3.4.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the subsequent period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Steam and Power Conversion System components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the current licensing basis during the subsequent period of extended operation.

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 001	Steel piping, piping components exposed to any environment	Cumulative fatigue damage due to fatigue	TLAA, SRP-SLR Section 4.3 “Metal Fatigue”	Yes	Fatigue is a TLAA; further evaluation is documented in Subsection 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	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage cracking of the stainless steel piping, piping components exposed to air and condensation in the Main Steam System, Condensate/Demineralized Water System, Reactor Feedwater System, and Condenser Circulating Water System See Subsection 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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to demonstrate the absence of loss of material of the stainless steel piping, piping components exposed to air and condensation in the Main Steam System, Condensate/Demineralized Water System, Reactor Feedwater System, and Condenser Circulating Water System. See Subsection 3.4.2.2.3.
3.4-1, 004	PWR Only				

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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. The Flow-Accelerated Corrosion program (B.2.1.9) will be used to manage wall thinning of the carbon steel piping, piping components exposed to steam or treated water in the Main Steam System, Condensate/Demineralized Water System, Reactor Feedwater System, Heater Drains and Vents System, Miscellaneous Turbine Connections System, and Auxiliary Boiler System.
3.4-1, 006	Metallic closure bolting exposed to any environment, soil, underground	Loss of preload due to thermal effects, gasket creep, self-loosening	AMP XI.M18, “Bolting Integrity”	No	Consistent with NUREG-2191. The Bolting Integrity program (B.2.1.10) will be used to manage loss of preload of the carbon and low alloy steel and stainless steel closure bolting exposed to air in the Main Steam System, Condensate/Demineralized Water System, Reactor Feedwater System, Heater Drains and Vents System, Miscellaneous Turbine Connections System, Condenser Circulating Water System, and Gland Seal Water System.
3.4-1, 007	High-strength steel closure bolting exposed to air, soil, underground	Cracking due to SCC; cyclic loading	AMP XI.M18, “Bolting Integrity”	No	Consistent with NUREG-2191. The Bolting Integrity program (B.2.1.10) will be used to manage cracking due to SCC, cyclic loading of high-strength steel closure bolting exposed to air, soil, underground within the screened-in portions of the Main Steam System, Condensate/ Demineralized Water System, and Reactor Feedwater System.
3.4-1, 008	This Item Number is not used in NUREG-2192.				

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 009	Steel, stainless steel, nickel alloy closure bolting exposed to air- indoor uncontrolled, air-outdoor, condensation	Loss of material due to general (steel only), pitting, crevice corrosion	AMP XI.M18, “Bolting Integrity”	No	Consistent with NUREG-2191. The Bolting Integrity program (B.2.1.10) will be used to manage loss of material from steel, stainless steel, and nickel alloy closure bolting exposed to air-indoor uncontrolled, air-outdoor, or condensation in the Main Steam System, Condensate/ Demineralized Water System, Reactor Feedwater System, Heater Drains and Vents System, Miscellaneous Turbine Connections System, Condenser Circulating Water System, and Gland Seal Water System.
3.4-1, 010	This Item Number is not used in NUREG-2192.				
3.4-1, 011	Stainless steel piping, piping components, tanks, heat exchanger components exposed to steam, treated water >60°C (>140°F)	Cracking due to SCC	AMP XI.M2, “Water Chemistry,” and AMP XI.M32, “One-Time Inspection”	No	Consistent with NUREG-2191. The Water Chemistry program (B.2.1.2) and One-Time Inspection program (B.2.1.20) will be used to manage cracking due to SCC of stainless steel piping, piping components, tanks, heat exchanger components exposed to steam, treated water >60°C (>140°F) in the screened-in portions of the Main Steam System, Condensate/ Demineralized Water System, and Reactor Feedwater System.
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. The Water Chemistry program (B.2.1.2) and One-Time Inspection program (B.2.1.20) will be used to manage loss of material from steel tanks exposed to treated water within the screened-in portions of the Condensate/ Demineralized Water System, Reactor Feedwater System and Gland Seal Water System.

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 013	This Item Number is not used in NUREG-2192.				
3.4-1, 014	Steel piping, piping components exposed to steam, treated water	Loss of material due to general, pitting, crevice corrosion, MIC (treated water only)	AMP XI.M2, “Water Chemistry,” and AMP XI.M32, “One-Time Inspection”	No	Consistent with NUREG-2191. The Water Chemistry program (B.2.1.2) and One-Time Inspection program (B.2.1.20) will be used to manage loss of material from steel piping, piping components exposed to steam, treated water within the screened-in portions of the Main Steam System, Condensate/Demineralized Water System, Reactor Feedwater System, Heater Drains and Vents System, Miscellaneous Turbine Connections System, and Gland Seal Water System.
3.4-1, 015	Steel heat exchanger components exposed to treated water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M2, “Water Chemistry,” and AMP XI.M32, “One-Time Inspection”	No	Consistent with NUREG-2191. The Water Chemistry program (B.2.1.2) and One-Time Inspection program (B.2.1.20) will be used to manage loss of material from steel heat exchanger components exposed to treated water in the Condensate/ Demineralized Water System.
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. The Water Chemistry program (B.2.1.2) and One-Time Inspection program (B.2.1.20) will be used to manage loss of material from copper alloy, and aluminum piping, piping components exposed to treated water, or treated borated water within the screened-in portions of the Condensate/ Demineralized Water System, Gland Seal Water System, and Reactor Core Isolation Cooling System.
3.4-1, 017	This Item Number is not used in NUREG-2192.				

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 018	Copper alloy, stainless steel heat exchanger tubes exposed to treated water	Reduction of heat transfer due to fouling	AMP XI.M2, “Water Chemistry,” and AMP XI.M32, “One-Time Inspection”	No	Consistent with NUREG-2191. The Water Chemistry program (B.2.1.2) and One-Time Inspection program (B.2.1.20) will be used to manage reduction of heat transfer due to fouling of copper alloy, and stainless steel heat exchanger tubes exposed to treated water within the screened-in portions of the Reactor Core Isolation Cooling System and High Pressure Coolant Injection System.
3.4-1, 019	Stainless steel, steel heat exchanger components exposed to raw water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, “Open-Cycle Cooling Water System”	No	Not Applicable. There are no stainless steel or steel heat exchanger components exposed to raw water in the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 020	Copper alloy, stainless steel piping, piping components exposed to raw water	Loss of material due to general (copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M20, “Open-Cycle Cooling Water System”	No	Not Applicable. There are no copper alloy or stainless steel piping, piping components exposed to raw water in the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 021	This Item Number is not used in NUREG-2192.				

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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	Not Applicable. The Condensate Pump Lube Oil Coolers and the Condensate Booster Pump Lube Oil Coolers in the Condensate/ Demineralized Water System, and the Condenser Circulating Water pump motors in the Condenser Circulating Water System have heat exchanger tubes exposed to raw water. However, these components are evaluated in the respective raw water systems cooling these components (see Section 3.3). The stainless steel main condenser tubes in the Condenser Circulating Water System do not have a heat transfer intended function and are consequently not subject to this Aging Effect/ Mechanism. There are no other stainless steel, copper alloy, or steel heat exchanger tubes exposed to raw water in the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 023	Stainless steel piping, piping components exposed to closed-cycle cooling water >60°C (>140°F)	Cracking due to SCC	AMP XI.M21A, “Closed Treated Water Systems”	No	Not Applicable. There are no stainless steel piping, piping components exposed to closed-cycle cooling water >140 F in the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 024	This Item Number is not used in NUREG-2192.				

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 025	Steel heat exchanger components exposed to closed-cycle cooling water	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M21A, “Closed Treated Water Systems”	No	Not Applicable. There are no steel heat exchanger components exposed to closed-cycle cooling water in the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 026	Stainless steel heat exchanger components, piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, “Closed Treated Water Systems”	No	Not Applicable. There are no stainless steel heat exchanger components or piping, piping components exposed to closed-cycle cooling water in the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 027	Copper alloy piping, piping components exposed to closed-cycle cooling water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M21A, “Closed Treated Water Systems”	No	Not Applicable. There are no copper alloy piping, piping components exposed to closed-cycle cooling water in the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 028	Steel, stainless steel, copper alloy heat exchanger tubes exposed to closed-cycle cooling water	Reduction of heat transfer due to fouling	AMP XI.M21A, “Closed Treated Water Systems”	No	Not Applicable. There are no steel, stainless steel, or copper alloy heat exchanger tubes exposed to closed-cycle cooling water in the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 029	This Item Number is not used in NUREG-2192.				

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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. The Outdoor and Large Atmospheric Metallic Storage Tanks program (B.2.1.17) will be used to manage loss of material from steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to soil, concrete, air, or condensation within the screened-in portions of the Condensate/Demineralized Water System. Exceptions apply to the NUREG-2191 recommendations for Outdoor and Large Atmospheric Metallic Storage Tanks program (B.2.1.17) implementation.
3.4-1, 031	This Item Number is not used in NUREG-2192.				
3.4-1, 032	Gray cast iron, ductile iron piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, “Selective Leaching”	No	Not Applicable. There are no gray cast iron or ductile iron piping, piping components exposed to soil in the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 033	Gray cast iron, ductile iron, copper alloy (>15% Zn or >8% Al) piping, piping components exposed to treated water, raw water, closed-cycle cooling water	Loss of material due to selective leaching	AMP XI.M33, “Selective Leaching”	No	Consistent with NUREG-2191. The Selective Leaching program (B.2.1.21) will be used to manage loss of material from gray cast iron, ductile iron, and copper alloy (>15% Zn or >8% Al) piping, piping components exposed to treated water, raw water, or closed-cycle cooling water in the Condensate/Demineralized Water System, Gland Seal Water System, and Reactor Core Isolation Cooling System.

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 034	Steel external surfaces exposed to air – indoor uncontrolled, air – outdoor, condensation	Loss of material due to general, pitting, crevice corrosion	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage loss of material of carbon steel and cast iron heat exchanger components, piping, piping components, and tanks exposed to air - indoor uncontrolled, air - outdoor or condensation in the Main Steam System, Condensate/Demineralized Water System, Reactor Feedwater System, Heater Drains and Vents System, Miscellaneous Turbine Connections System, Condenser Circulating Water System, and Gland Seal Water System.
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	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage loss of material from aluminum piping, piping components and tanks exposed to air in the Main Steam System, and Condensate/ Demineralized Water Systems. See Subsection 3.4.2.2.9.
3.4-1, 036	Steel piping, piping components exposed to air – outdoor	Loss of material due to general, pitting, crevice corrosion	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Not Applicable. There are no steel piping, piping components internal surfaces exposed to air – outdoor within the screened-in portions of the Steam and Power Conversion Systems.

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) will be used to manage loss of material from steel piping, piping components exposed to condensation in the screened-in portions of the Condenser Circulating Water System.
3.4-1, 038	PWR Only				
3.4-1, 039	This Item Number is not used in NUREG-2192.				
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. The Lubricating Oil Analysis program (B.2.1.25) and the One-Time Inspection program (B.2.1.20) will be used to manage loss of material in the steel piping components exposed to lubricating oil in the Condensate/Demineralized Water System. There are no other steel piping, piping components exposed to lubricating oil in the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 041	PWR Only				
3.4-1, 042	PWR Only				
3.4-1, 043	Copper alloy piping, piping components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M39, “Lubricating Oil Analysis,” and AMP XI.M32, “One-Time Inspection”	No	Not Applicable There are no copper alloy piping, piping components exposed to lubricating oil in the screened-in portions of the Steam and Power Conversion Systems.

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 044	Stainless steel piping, piping components, heat exchanger components exposed to lubricating oil	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M39, “Lubricating Oil Analysis,” and AMP XI.M32, “One-Time Inspection”	No	Not Applicable There are no stainless steel piping, piping components, heat exchanger components exposed to lubricating oil in the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 045	Aluminum heat exchanger tubes exposed to lubricating oil	Reduction of heat transfer due to fouling	AMP XI.M39, “Lubricating Oil Analysis,” and AMP XI.M32, “One-Time Inspection”	No	Not Applicable. There are no aluminum heat exchanger tubes exposed to lubricating oil in the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 046	PWR Only				
3.4-1, 047	Stainless steel piping, piping components, tanks, closure bolting exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, “Buried and Underground Piping and Tanks”	No	Not Applicable There are no stainless steel piping, piping components, tanks, closure bolting exposed to soil, concrete within the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 048	Nickel alloy piping, piping components, tanks, closure bolting exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, “Buried and Underground Piping and Tanks”	No	Not Applicable. There are no nickel alloy piping, piping components, tanks, or closure bolting exposed to soil or concrete in the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 049	This Item Number is not used in NUREG-2192.				

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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 with exceptions. The Buried and Underground Piping and Tanks program (B.2.1.27) will be used to manage loss of material from steel piping, piping components, tanks or closure bolting exposed to soil, concrete, or underground within the screened-in portions of the Condensate/Demineralized Water System and Condenser Circulating Water System. Exceptions apply to the NUREG-2191 recommendations for Buried and Underground Piping and Tanks program (B.2.1.27) implementation.
3.4-1, 050a	This Item Number is not used in NUREG-2192.				
3.4-1, 051	Steel piping, piping components exposed to concrete	None	None	Yes	Consistent with NUREG-2191. The only Steam and Power Conversion Systems where steel piping, piping components are exposed to concrete within the screened-in portion of the system are the Condensate/ Demineralized Water System and the Condenser Circulating Water System. See Subsection 3.4.2.2.8.
3.4-1, 052	Aluminum piping, piping components exposed to gas	None	None	No	Not Applicable. There are no aluminum piping, piping components exposed to gas in the screened-in portions of the Steam and Power Conversion Systems.

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 053	Copper alloy, copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage	None	None	No	Not Applicable. There are no copper alloy, copper alloy (>8% Al) piping, piping components exposed to air with borated water leakage in the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 054	Copper alloy piping, piping components exposed to air, condensation, gas	None	None	No	Consistent with NUREG-2191. Copper alloy piping, piping components exposed to air, condensation, gas within the screened-in portions of the Condensate/ Demineralized Water System, Reactor Feedwater System, Condenser Circulating Water System, and Gland Seal Water System does not require any Aging Management Program.
3.4-1, 055	Glass piping elements exposed to lubricating oil, air, condensation, raw water, treated water, air with borated water leakage, gas, closed-cycle cooling water	None	None	No	Consistent with NUREG-2191. Glass piping elements exposed to lubricating oil, air, condensation, raw water, treated water, air with borated water leakage, gas, or closed-cycle cooling water within the screened-in portions of the Gland Seal Water System do not require any Aging Management Program.
3.4-1, 056	Nickel alloy piping, piping components exposed to air with borated water leakage	None	None	No	Not Applicable. There are no nickel alloy piping, piping components exposed to air with borated water leakage in the screened-in portions of the Steam and Power Conversion Systems.

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 057	PVC piping, piping components exposed to air – indoor uncontrolled, condensation	None	None	No	Consistent with NUREG-2191. There is no Aging Effect/Mechanism or Aging Management Program required for the PVC piping, piping components exposed to air – indoor uncontrolled or condensation in the screened-in portions of the Condensate/Demineralized Water System.
3.4-1, 058	Stainless steel piping, piping components exposed to gas	None	None	No	Not Applicable. There are no stainless steel piping, piping components exposed to gas in the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 059	Steel piping, piping components exposed to air – indoor controlled, gas	None	None	No	Not Applicable. There are no steel piping, piping components exposed to air – indoor controlled or gas in the screened-in portions of the Steam and Power Conversion Systems.
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. The Flow-Accelerated Corrosion program (B.2.1.9) will be used to manage wall thinning due to erosion of carbon steel, stainless steel and gray cast iron piping, piping components exposed to steam and treated water in the Main Steam System, Condensate/ Demineralized Water System, Reactor Feedwater System, Heater Drains and Vents System, and Miscellaneous Turbine Connections System.

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Not Applicable. There are no components within the Steam and Power Conversion Systems where the frequency and severity for loss of material met the thresholds that would require augmenting the aging management recommendations in the GALL-SLR Report to manage loss of material due to recurring internal corrosion. See Subsection 3.4.2.2.6.
3.4-1, 062	Steel, stainless steel or aluminum tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to treated water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC (steel, stainless steel only)	AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”	No	Consistent with NUREG-2191 with exceptions. The Outdoor and Large Atmospheric Metallic Storage Tanks program (B.2.1.17) will be used to manage loss of material from steel, stainless steel or aluminum tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to treated water in the Condensate/Demineralized Water System. Exceptions apply to the NUREG-2191 recommendations for Outdoor and Large Atmospheric Metallic Storage Tanks program (B.2.1.17) implementation.

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage loss of material from 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 within the screened-in portions of the Reactor Feedwater System. There are no steel insulated tanks (within the scope of AMP XI.M29, "Outdoor and Large Metallic Storage Tanks" within the screened-in portions of the Steam and Power Conversion Systems.
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. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage reduced thermal insulation resistance due to moisture intrusion for non-metallic thermal insulation exposed to air, as shown in Table 3.5.2-36, Structural Commodities (Thermal Insulation), in the Main Steam System, Condensate/Demineralized Water System, Reactor Feedwater System, and Heater Drains and Vents System.
3.4-1, 065	This Item Number is not used in NUREG-2192.				

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 066	Any material piping, piping components, heat exchangers, tanks with internal coatings/ linings exposed to closed-cycle cooling water, raw water, treated water, lubricating oil	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage; loss of material or cracking for cementitious coatings/ linings	AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Consistent with NUREG-2191. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (B.2.1.28) will be used to manage loss of coating or lining integrity of the stainless steel tanks with internal coating exposed to treated water in the Condensate/ Demineralized Water System. The Outdoor and Large Atmospheric Metallic Storage Tanks program (B.2.1.17) has been substituted and will be used to manage loss of coating or lining integrity of the carbon steel tanks with internal coating exposed to treated water in the Condensate/Demineralized Water System. Exceptions apply to the NUREG-2191 recommendations for Outdoor and Large Atmospheric Metallic Storage Tanks program (B.2.1.17) implementation.

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**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. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (B.2.1.28) will be used to manage loss of material from the stainless steel tanks with internal coating exposed to treated water in the Condensate/Demineralized Water System. The Outdoor and Large Atmospheric Metallic Storage Tanks program (B.2.1.17) has been substituted and will be used to manage loss of material from the carbon steel tanks with internal coating exposed to treated water in the Condensate/ Demineralized Water System. Exceptions apply to the NUREG-2191 recommendations for Outdoor and Large Atmospheric Metallic Storage Tanks program (B.2.1.17) 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. There are no 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 screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 069	This Item Number is not used in NUREG-2192.				

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191. The Bolting Integrity program (B.2.1.10) will be used to manage loss of material from stainless steel, steel, nickel alloy, copper alloy closure bolting exposed to lubricating oil, treated water, treated borated water, raw water, or waste water in the Main Steam System, Condensate/Demineralized Water System, Reactor Feedwater System, Heater Drains and Vents System, Miscellaneous Turbine Connections System, Condenser Circulating Water System, and Gland Seal Water System.
3.4-1, 071	This Item Number is not used in NUREG-2192.				
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 with exceptions. The Buried and Underground Piping and Tanks program (B.2.1.27) will be used to manage cracking due to SCC of stainless steel, steel, aluminum piping, and piping components, tanks exposed to concrete (steel in carbonate / bicarbonate environment only) within the screened-in portions of the Condenser Circulating Water System. Exceptions apply to the NUREG-2191 recommendations for Buried and Underground Piping and Tanks program (B.2.1.27) implementation. The Condensate Storage Tanks are steel and the tank bottoms are exposed to soil, concrete. However, the steel Condensate Storage Tanks are managed by the Outdoor and Large Atmospheric Metallic Storage Tanks program (B.2.1.17) for exposure to soil, concrete, air, condensation environments. See Item Number 3.4-1, 030.

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 073	Stainless steel closure bolting exposed to air, soil, concrete, underground, waste water	Cracking due to SCC	AMP XI.M18, “Bolting Integrity”	No	Consistent with NUREG-2191. The Bolting Integrity program (B.2.1.10) will be used to manage cracking due to SCC of stainless steel closure bolting exposed to air, soil, concrete, underground, or waste water in the Main Steam System, Condensate/ Demineralized Water System and Reactor Feedwater System.
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	Not applicable. There are no stainless steel underground piping, piping components, or tanks within the screened-in portions of the Steam and Power Conversion Systems. See Subsection 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. There are no stainless steel, steel, aluminum, copper alloy, or titanium heat exchanger tubes exposed to air, or condensation within the screened in portions of the Steam and Power Conversion Systems that have a passive function requiring heat transfer. Consequently, management of the aging effect, reduction of heat transfer due to fouling, is not required.
3.4-1, 076	This Item Number is not used in NUREG-2192.				

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 077	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	Not Applicable. There are no elastomer piping, piping components, or seals exposed to air or condensation within the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 078	Elastomer piping, piping components, seals exposed to air, condensation	Hardening or loss of strength due to elastomer degradation	AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Not Applicable. There are no elastomer piping, piping components, or seals exposed to air or condensation within the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 079	This Item Number is not used in NUREG-2192.				
3.4-1, 080	This Item Number is not used in NUREG-2192.				
3.4-1, 081	Steel components exposed to treated water, raw water	Long-term loss of material due to general corrosion	AMP XI.M32, “One-Time Inspection”	No	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to demonstrate the absence of long-term loss of material from steel components exposed to treated water, or raw water within the screened-in portions of the Condensate/Demineralized Water System, Heater Drains and Vents System, Miscellaneous Turbine Connections System, and Condenser Circulating Water System.

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 082	Stainless steel piping, piping components exposed to concrete	None	None	Yes	Consistent with NUREG-2191. The only Steam and Power Conversion System where stainless steel piping, piping components are exposed to concrete within the screened-in portion of the system is the Condensate/Demineralized Water System. Loss of material and cracking due to SCC are not considered to be applicable aging effects for portions of the stainless steel piping and piping components exposed to concrete that is indoors, or outdoors and above ground level, in the screened-in portions of the Condensate/Demineralized Water System because the piping is not potentially exposed to groundwater. There are no stainless steel piping and piping components in the screened-in portions of the Condensate/Demineralized Water System that are exposed to concrete, and are outdoors and below ground level, susceptible to loss of material and cracking due to SCC (because the piping is potentially exposed to groundwater). See Subsection 3.4.2.2.8.
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. The Water Chemistry program (B.2.1.2) and One-Time Inspection program (B.2.1.20) will be used to manage loss of material from stainless steel, nickel alloy tanks exposed to treated water in the screened-in portions of the Condensate/Demineralized Water System, Spent Fuel Pool Cooling/Cleanup System, and Control Rod Drive System.

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 084	Stainless steel, nickel alloy piping, piping components exposed to steam	Loss of material due to pitting, crevice corrosion	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Water Chemistry program (B.2.1.2) and One-Time Inspection program (B.2.1.20) will be used to manage loss of material from stainless steel, nickel alloy piping, piping components exposed to steam in the screened-in portions of the Main Steam System.
3.4-1, 085	Stainless steel, nickel alloy piping, piping components, PWR heat exchanger components exposed to treated water	Loss of material due to pitting, crevice corrosion, MIC	AMP XI.M2, "Water Chemistry," and AMP XI.M32, "One-Time Inspection"	No	Consistent with NUREG-2191. The Water Chemistry program (B.2.1.2) and One-Time Inspection program (B.2.1.20) will be used to manage loss of material from stainless steel, and nickel alloy piping, piping components exposed to treated water in the Condensate/Demineralized Water System, and Reactor Feedwater System. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) is substituted to manage loss of material from stainless steel heat exchanger components exposed to treated water in the Condensate/Demineralized Water System and Reactor Feedwater System.
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. None of the heat exchangers in the screened-in portions of the Steam and Power Conversion Systems have a passive function requiring heat transfer. Consequently, the Aging Effect, Reduction of Heat Transfer due to Fouling, is not required to be managed. Condenser and heater tubes are stainless steel.
3.4-1, 087	This Item Number is not used in NUREG-2192.				

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 088	This Item Number is not used in NUREG-2192.				
3.4-1, 089	Steel, stainless steel, copper alloy piping, piping components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) will be used to manage loss of material from steel, stainless steel, or copper alloy piping, piping components exposed to raw water (for components not covered by NRC GL 89-13) within the screened-in portions of the Condenser Circulating Water System.
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. None of the heat exchangers in the screened-in portions of the Steam and Power Conversion Systems have a passive function requiring heat transfer. Consequently, the Aging Effect, Reduction of Heat Transfer due to Fouling, is not required to be managed. Main condenser and heater tubes are stainless steel.
3.4-1, 091	Steel, stainless steel, copper alloy heat exchanger components exposed to raw water (for components not covered by NRC GL 89-13)	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) will be used to manage loss of material from steel, stainless steel, or copper alloy heat exchanger components exposed to raw water (for components not covered by NRC GL 89-13) within the screened-in portions of the Condenser Circulating Water System.

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 092	Copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	Not Applicable. There are no copper alloy (>15% Zn or >8% Al) piping, piping components exposed to soil in the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 093	This Item Number is not used in NUREG-2192.				
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	Not applicable. There are no aluminum underground piping, piping components, or tanks within the screened-in portions of the Steam and Power Conversion Systems. See Subsection 3.4.2.2.9.
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	Not applicable. There are no stainless steel and nickel alloy underground piping, piping components, or tanks within the screened-in portions of the Steam and Power Conversion Systems. See Subsection 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. There are no aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to soil or concrete in the screened-in portions of the Steam and Power Conversion Systems.

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 097	Aluminum tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks,” AMP XI.M32, “One-Time Inspection,” or AMP XI.M42, “Internal Coatings / Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks”	Yes	Not Applicable. There are no aluminum tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) in the screened-in portions of the Steam and Power Conversion Systems. See Subsection 3.4.2.2.9.
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	Not Applicable. There are no stainless steel or nickel alloy tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to air, condensation in the screened-in portions of the Steam and Power Conversion Systems. See Subsection 3.4.2.2.3.
3.4-1, 099	Stainless steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”	No	Not Applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to soil or concrete in the screened-in portions of the Steam and Power Conversion Systems.

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 100	Stainless steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to air, condensation	Cracking due to SCC	AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks,” AMP XI.M32, “One-Time Inspection,” or AMP XI.M42, “Internal Coatings / Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks”	Yes	Not Applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to air or condensation in the screened-in portions of the Steam and Power Conversion Systems. See Subsection 3.4.2.2.2.
3.4-1, 101	Stainless steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to soil, concrete	Cracking due to SCC	AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”	No	Not Applicable. There are no stainless steel tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to soil or concrete within the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 102	Aluminum tanks (within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”) exposed to air, condensation, soil, concrete, raw water, waste water	Cracking due to SCC	AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks,” AMP XI.M32, “One-Time Inspection,” or AMP XI.M42, “Internal Coatings / Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks”	Yes	Not Applicable. There are no 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 within the screened-in portions of the Steam and Power Conversion Systems. See Subsection 3.4.2.2.7.

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 103	Insulated stainless steel, nickel alloy piping, piping components, tanks exposed to air, condensation	Loss of material due to pitting, crevice corrosion	AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks,” AMP XI.M32, “One-Time Inspection,” AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” or AMP XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks”	Yes	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to demonstrate the absence of loss of material due to pitting, crevice corrosion in insulated stainless steel piping and piping components exposed to air, condensation environments in the screened-in portions of the Main Steam System, Condensate/Demineralized Water System, and Reactor Feedwater System. See Subsection 3.4.2.2.3.
3.4-1, 104	Insulated stainless steel piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks,” AMP XI.M32, “One-Time Inspection,” AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” or AMP XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks”	Yes	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to demonstrate the absence of cracking in screened-in insulated stainless steel piping and piping components, tanks exposed to air, condensation environments in the screened-in portions of the Main Steam System, Condensate/ Demineralized Water System and Reactor Feedwater System. See Subsection 3.4.2.2.2.

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 105	Insulated aluminum piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks,” AMP XI.M32, “One-Time Inspection,” AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” or AMP XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks”	Yes	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to demonstrate the absence of cracking in insulated aluminum piping, piping components, tanks exposed to air, condensation environments within the screened-in portions of the Condensate/ Demineralized Water System. See Subsection 3.4.2.2.7.
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. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage cracking due to SCC of copper alloy (>15% Zn or >8% Al) piping, piping components exposed to air, condensation within the screened-in portions of the Condensate/ Demineralized Water System, Reactor Feedwater System, and Gland Seal Water System.
3.4-1, 107	Copper alloy (>15% Zn or >8% Al) tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	Not Applicable. There are no copper alloy (>15% Zn or >8% Al) tanks exposed to air or condensation within the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 108	This Item Number is not used in NUREG-2192.				

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 109	Aluminum piping, piping components, tanks exposed to air, condensation, raw water, waste water	Cracking due to SCC	AMP XI.M32, “One-Time Inspection,” AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,” or AMP XI.M42, “Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks”	Yes	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage the aging effect of cracking due to SCC in aluminum piping, piping components and tanks exposed to air, condensation, raw water, waste water environments within the screened-in portions of the Main Steam System and Condensate/ Demineralized Water System. See Subsection 3.4.2.2.7.
3.4-1, 110	This Item Number is not used in NUREG-2192.				
3.4-1, 111	This Item Number is not used in NUREG-2192.				
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	Not applicable. There are no aluminum underground piping, piping components, or tanks within the screened-in portions of the Condensate/Demineralized Water System. See Subsection 3.4.2.2.7.
3.4-1, 113	This Item Number is not used in NUREG-2192.				

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 114	Titanium heat exchanger tubes exposed to treated water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M2, “Water Chemistry,” and AMP XI.M32, “One-Time Inspection”	No	Not Applicable. There are no titanium heat exchanger tubes exposed to treated water within the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 115	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to treated water	None	None	No	Not Applicable There are no titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, or piping components exposed to treated water within the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 116	Titanium heat exchanger tubes exposed to closed- cycle cooling water	Cracking due to SCC, reduction of heat transfer due to fouling	AMP XI.M21A, “Closed Treated Water Systems”	No	Not Applicable. There are no titanium heat exchanger tubes exposed to closed cycle cooling water within the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 117	Aluminum piping, piping components, tanks exposed to soil, concrete	Loss of material due to pitting, crevice corrosion	AMP XI.M41, “Buried and Underground Piping and Tanks”	No	Not Applicable. There are no aluminum piping, piping components or tanks exposed to soil or concrete within the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 118	This Item Number is not used in NUREG-2192.				

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
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	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to manage loss of material from insulated aluminum piping and piping components exposed to air, condensation environments within the screened-in portions of the Condensate/ Demineralized Water System. See Subsection 3.4.2.2.9.
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	Not Applicable. There are no aluminum piping, piping components, or tanks exposed to raw water or waste water within the screened-in portions of the Steam and Power Conversion Systems. See Subsection 3.4.2.2.9.
3.4-1, 121	This Item Number is not used in NUREG-2192.				
3.4-1, 122	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M36, “External Surfaces Monitoring of Mechanical Components”	No	Not Applicable. There are no elastomer piping, piping components, or seals exposed to air within the screened-in portions of the Steam and Power Conversion Systems.

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 123	Elastomer piping, piping components, seals exposed to air	Loss of material due to wear	AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Not Applicable. There are no elastomer piping, piping components, or seals exposed to air within the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 124	PVC piping, piping components, tanks exposed to concrete	None	None	No	Not Applicable. There are no PVC piping, piping components, or tanks exposed to concrete within the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 125	PVC piping, piping components, tanks exposed to soil	Loss of material due to wear	AMP XI.M41, “Buried and Underground Piping and Tanks”	No	Not Applicable. There are no PVC piping, piping components, or tanks exposed to soil within the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 126	Titanium (ASTM Grades 1, 2, 7, 9, 11, or 12) heat exchanger components other than tubes, piping, piping components exposed to closed-cycle cooling water	None	None	No	Not Applicable. There are no titanium (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 within the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 127	Aluminum piping, piping components, tanks exposed to air with borated water leakage	None	None	No	Not Applicable. There are no aluminum piping, piping components, or tanks exposed to air with borated water leakage within the screened-in portions of the Steam and Power Conversion Systems.

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 128	Copper alloy piping, piping components exposed to concrete	None	None	No	Not Applicable. There are no copper alloy piping, piping components exposed to concrete within the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 129	Copper alloy piping, piping components exposed to soil, underground	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, “Buried and Underground Piping and Tanks”	No	Not applicable. There are no copper alloy piping, piping components exposed to soil or underground within the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 130	Titanium piping, piping components, heat exchanger components other than tubes exposed to raw water	Cracking due to SCC, flow blockage due to fouling	AMP XI.M20, “Open-Cycle Cooling Water System,” or AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Not Applicable. There are no titanium piping, piping components, heat exchanger components other than tubes exposed to raw water within the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 131	PWR Only				
3.4-1, 132	PWR Only				
3.4-1, 133	Aluminum piping, piping components exposed to raw water	Flow blockage due to fouling	AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Not Applicable. There are no aluminum piping, piping components exposed to raw water within the screened-in portions of the Steam and Power Conversion Systems.

Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion Systems (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4-1, 134	Titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water	Cracking due to SCC	AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Not Applicable. There are no titanium (ASTM Grades 3, 4, or 5) heat exchanger tubes exposed to raw water within the screened-in portions of the Steam and Power Conversion Systems.
3.4-1, 135	Polymeric piping, piping components, ducting, ducting components, seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, soil	Hardening or loss of strength due to polymeric degradation; loss of material due to peeling, delamination, wear; cracking or blistering due to exposure to ultraviolet light, ozone, radiation, or chemical attack; flow blockage due to fouling	AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” or AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components”	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components program (B.2.1.23) or Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) will be used to manage 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 of polymeric piping, piping components, ducting, ducting components, and seals exposed to air, condensation, raw water, raw water (potable), treated water, waste water, underground, concrete, or soil within the screened-in portions of the Condensate/ Demineralized Water System.

Table 3.4.2-1, Main Steam System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air - indoor uncontrolled	Cracking due to SCC	Bolting Integrity (B.2.1.10)	IV.C1.R-11	3.1-1, 062	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion, wear	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1-1, 063	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled (external)	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1-1, 067	A
Closure bolting	Mechanical Closure	Steel	Any	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4-1, 006	A, 2
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VIII.H.S-03	3.4-1, 007	A
Closure bolting	Mechanical Closure	Stainless Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VIII.H.S-02	3.4-1, 009	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VIII.H.S-02	3.4-1, 009	A
Closure bolting	Mechanical Closure	Stainless Steel	Treated 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)	Bolting Integrity (B.2.1.10)	VIII.H.S-418	3.4-1, 070	A, 2

Table 3.4.2-1, Main Steam System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	Steel	Treated 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)	Bolting Integrity (B.2.1.10)	VIII.H.S-418	3.4-1, 070	A, 2
Closure bolting	Mechanical Closure	Stainless steel	Air	Cracking due to SCC	Bolting Integrity (B.2.1.10)	VIII.H.S-421	3.4-1, 073	A
External surfaces	Pressure Boundary, Holdup and Plateout	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4-1, 034	A
Insulated piping, piping components, tanks	Pressure Boundary	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VIII.H.S-451b	3.4-1, 103	A
Insulated piping, piping components, tanks	Pressure Boundary	Stainless steel	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VIII.H.S-452b	3.4-1, 104	A
Reactor coolant pressure boundary components: piping, piping components; other pressure retaining components with fatigue analyses	Pressure Boundary	Steel (with or without nickel alloy or stainless steel cladding)	Reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A

Table 3.4.2-1, Main Steam System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Class 1 piping, fittings and branch connections < NPS 4	Pressure Boundary	Stainless steel	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), thermal, mechanical, vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1), Water Chemistry (B.2.1.2), and ASME Code Class 1 Small-bore Piping (B.2.1.22)	IV.C1.RP-230	3.1-1, 039	A
Class 1 piping, fittings and branch connections < NPS 4	Pressure Boundary	Steel (with or without nickel alloy or stainless steel cladding)	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), thermal, mechanical, vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1), Water Chemistry (B.2.1.2), and ASME Code Class 1 Small-bore Piping (B.2.1.22)	IV.C1.RP-230	3.1-1, 039	A
Class 1 piping, piping components, including pump casings	Pressure Boundary, Throttle	Cast austenitic stainless steel	Reactor coolant >250°C (>482°F)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B.2.1.8)	IV.C1.R-52	3.1-1, 050	A
Piping, piping components	Pressure Boundary	Steel	Reactor coolant	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-23	3.1-1, 060	A
Reactor coolant pressure boundary components	Pressure Boundary	Stainless Steel	Reactor coolant	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	A

Table 3.4.2-1, Main Steam System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components greater than or equal to 4 NPS	Pressure Boundary	Stainless steel	Reactor coolant	Cracking due to SCC, IGSCC	BWR Stress Corrosion Cracking, (B.2.1.5) and Water Chemistry (B.2.1.2)	IV.C1.R-20	3.1-1, 097	B
Piping, piping components	Pressure Boundary, Holdup and Plateout	Cast Austenitic Stainless Steel	Reactor Coolant	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-406	3.1-1, 110	A
Piping, piping components	Pressure Boundary, Holdup and Plateout	Stainless steel	Reactor Coolant	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-406	3.1-1, 110	A
Piping, piping components	Pressure Boundary, Holdup and Plateout	Steel	Reactor Coolant	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-406	3.1-1, 110	A
Reactor coolant system components: Components defined as ASME Section XI components (e.g., reactor coolant pressure boundary components, core support structure components, ASME Class 2 or 3 components, including associated pressure retaining welds) not managed by other AMR line items in GALL-SLR Chapter IV	Pressure Boundary, Throttle	Stainless Steel	Air	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, (B.2.1.1) and Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A

Table 3.4.2-1, Main Steam System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Reactor coolant system components: Components defined as ASME Section XI components (e.g., reactor coolant pressure boundary components, core support structure components, ASME Class 2 or 3 components, including associated pressure retaining welds) not managed by other AMR line items in GALL-SLR Chapter IV	Pressure Boundary	Steel	Air	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, (B.2.1.1) and Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
Reactor coolant system components: Components defined as ASME Section XI components (e.g., reactor coolant pressure boundary components, core support structure components, ASME Class 2 or 3 components, including associated pressure retaining welds) not managed by other AMR line items in GALL-SLR Chapter IV	Pressure Boundary	Steel	Treated water	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, (B.2.1.1) and Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
Piping, piping components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A

Table 3.4.2-1, Main Steam System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Treated water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1-1, 133	A
Piping, piping components	Pressure Boundary	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Piping, piping components	Pressure Boundary	Aluminum	Air - dry	Loss of material due to general (steel only), pitting, crevice corrosion	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3-1, 235	A, 1
Piping, piping components	Pressure Boundary	Steel	Air - dry	Loss of material due to general (steel only), pitting, crevice corrosion	Compressed Air Monitoring (B.2.1.14)	VII.D.A-764	3.3-1, 235	A
Piping, piping components	Pressure Boundary, Holdup and Plateout	Steel	Treated Water	Cumulative fatigue damage due to fatigue	Section 4.3 “Metal Fatigue”	VIII.B2.S-08	3.4-1, 001	A
Piping, piping components, tanks	Pressure Boundary	Stainless steel	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VIII.B2.SP-118a	3.4-1, 002	A
Piping, piping components	Pressure Boundary, Holdup and Plateout	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VIII.B2.SP-127a	3.4-1, 003	A
Piping, piping components	Pressure Boundary, Holdup and Plateout	Steel	Steam	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.B2.S-15	3.4-1, 005	A
Piping, piping components	Pressure Boundary, Holdup and Plateout	Stainless steel	Steam	Cracking due to SCC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.B2.SP-98	3.4-1, 011	A

Table 3.4.2-1, Main Steam System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary, Holdup and Plateout	Steel	Steam	Loss of material due to general, pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.B2.SP-160	3.4-1, 014	A
Piping, piping components	Pressure Boundary, Holdup and Plateout	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.B2.SP-73	3.4-1, 014	A
Piping, piping components	Pressure Boundary	Aluminum	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VIII.E.SP-147a	3.4-1, 035	A, 1
Piping, piping components	Pressure Boundary	Stainless steel	Steam	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.B2.S-408	3.4-1, 060	A
Piping, piping components	Pressure Boundary, Holdup and Plateout	Stainless steel	Steam	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.B2.S-408	3.4-1, 060	A
Piping, piping components	Pressure Boundary	Steel	Steam	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.B2.S-408	3.4-1, 060	A
Piping, piping components	Pressure Boundary	Stainless steel	Steam	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.B2.SP-155	3.4-1, 084	A
Piping, piping components	Pressure Boundary	Aluminum	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VIII.D2.S-457b	3.4-1, 109	A, 1

Table 3.4.2-1 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. The only aluminum materials in the Main Steam System are the Control Air Solenoid Valve bodies.
2. This GALL-SLR item reflects consideration of leakage from a flanged connection. However, this system does not contain any submerged closure bolting.

Table 3.4.2-2, Condensate/Demineralized Water System - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Closure bolting	Mechanical Closure	Stainless steel	Any	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4-1, 006	A, 2
Closure bolting	Mechanical Closure	Steel	Any	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4-1, 006	A, 2
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VIII.H.S-03	3.4-1, 007	A
Closure bolting	Mechanical Closure	Stainless steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VIII.H.S-02	3.4-1, 009	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VIII.H.S-02	3.4-1, 009	A
Closure bolting	Mechanical Closure	Steel	Concrete	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	Buried and Underground Piping and Tanks (B.2.1.27)	VIII.H.SP-141	3.4-1, 050	B
Closure bolting	Mechanical Closure	Stainless steel	Treated 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)	Bolting Integrity (B.2.1.10)	VIII.H.S-418	3.4-1, 070	A, 2

Table 3.4.2-2, Condensate/Demineralized Water System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Closure bolting	Mechanical Closure	Steel	Treated 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)	Bolting Integrity (B.2.1.10)	VIII.H.S-418	3.4-1, 070	A, 2
Closure bolting	Mechanical Closure	Stainless steel	Air	Cracking due to SCC	Bolting Integrity (B.2.1.10)	VIII.H.S-421	3.4-1, 073	A
External surfaces	Pressure Boundary	Cast Iron and Cast Iron Alloys	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4-1, 034	A
External surfaces	Pressure Boundary	Cast Iron and Cast Iron Alloys	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4-1, 034	A
External surfaces	Filter, Holdup and Plateout, Pressure Boundary, Thermal Insulation Jacket Integrity	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4-1, 034	A
External surfaces	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4-1, 034	A
Heat exchanger components	Pressure Boundary	Steel with stainless steel cladding	Treated water >60°C (>140°F)	Cracking due to SCC	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E3.AP-112	3.3-1, 020	E, 3

Table 3.4.2-2, Condensate/Demineralized Water System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Heat exchanger components	Pressure Boundary	Steel	Lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	Lubricating Oil Analysis, (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.H2.AP-131	3.3-1, 098	A
Heat exchanger components	Pressure Boundary	Metallic	Raw water	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	VII.C1.A-409	3.3-1, 126	C, 1
Heat exchanger tubes	Heat Transfer	Copper alloy	Lubricating oil	Reduction of heat transfer due to fouling	Lubricating Oil Analysis, (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.C1.A-791	3.3-1, 257	A
Heat exchanger components	Pressure Boundary,	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.E.SP-77	3.4-1, 015	A
Heat exchanger components and tubes	Pressure Boundary,	Stainless steel	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.SP-80	3.4-1, 085	E, 3
Insulated piping, piping components, tanks	Pressure Boundary	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VIII.H.S-451b	3.4-1, 103	A
Insulated piping, piping components, tanks	Pressure Boundary	Stainless steel	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VIII.H.S-452b	3.4-1, 104	A
Insulated piping, piping components, tanks	Pressure Boundary	Aluminum	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VIII.H.S-453b	3.4-1, 105	A
Insulated piping, piping components, tanks	Pressure Boundary	Aluminum	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VIII.H.S-468b	3.4-1, 119	A

Table 3.4.2-2, Condensate/Demineralized Water System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Polymeric	Concrete	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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E5.A-797b	3.3-1, 263	A
Piping, piping components, tanks	Pressure Boundary	Stainless steel	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VIII.E.SP-118a	3.4-1, 002	A
Piping, piping components	Pressure Boundary	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VIII.E.SP-127a	3.4-1, 003	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.E.S-16	3.4-1, 005	A
Piping, piping components	Pressure Boundary	Stainless steel	Treated water >60°C (>140°F)	Cracking due to SCC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.E.SP-88	3.4-1, 011	A
Piping, piping components	Pressure Boundary	Steel	Steam	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.A.SP-71	3.4-1, 014	A
Piping, piping components	Pressure Boundary	Cast Iron and Cast Iron Alloy	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.E.SP-73	3.4-1, 014	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.E.SP-73	3.4-1, 014	A

Table 3.4.2-2, Condensate/Demineralized Water System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Copper alloy	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.A.SP-101	3.4-1, 016	A
Piping, piping components	Pressure Boundary	Aluminum	Treated water	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.E.SP-90	3.4-1, 016	A
Piping, piping components	Pressure Boundary	Ductile iron	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VIII.E.SP-27	3.4-1, 033	A
Piping, piping components	Pressure Boundary	Gray cast iron	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VIII.E.SP-27	3.4-1, 033	A
Piping, piping components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VIII.E.SP-55	3.4-1, 033	A
Piping, piping components	Pressure Boundary	Aluminum	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VIII.E.SP-147a	3.4-1, 035	A
Piping, piping components	Pressure Boundary	Steel	Lubricating oil	Loss of material due to general, pitting, crevice corrosion, MIC	Lubricating Oil Analysis, (B.2.1.25) and One-Time Inspection (B.2.1.20)	VIII.E.SP-91	3.4-1, 040	A
Piping, piping components	Pressure Boundary	Steel	Concrete	None	None	VIII.I.SP-154	3.4-1, 051	A
Piping, piping components	Pressure Boundary	Copper alloy	Air	None	None	VIII.I.SP-6	3.4-1, 054	A
Piping, piping components	Pressure Boundary	PVC	Air - indoor uncontrolled	None	None	VIII.I.SP-152	3.4-1, 057	A
Piping, piping components	Pressure Boundary	Metallic	Treated water	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.D2.S-408	3.4-1, 060	A

Table 3.4.2-2, Condensate/Demineralized Water System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components, heat exchangers, tanks with internal coatings/linings	Pressure Boundary	Stainless steel	Treated water	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, physical damage; loss of material or cracking for cementitious coatings/linings	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VIII.E.S-401	3.4-1, 066	A
Piping, piping components, heat exchangers, tanks with internal coatings/linings	Pressure Boundary	Stainless steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B.2.1.28)	VIII.E.S-414	3.4-1, 067	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	VIII.E.S-432	3.4-1, 081	A
Piping, piping components	Pressure Boundary	Stainless steel	Concrete	None	None	VIII.I.SP-13	3.4-1, 082	A
Piping, piping components	Pressure Boundary	Stainless steel	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.E.SP-87	3.4-1, 085	A
Piping, piping components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Air	Cracking due to SCC	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-454	3.4-1, 106	A
Piping, piping components	Pressure Boundary	Aluminum	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VIII.D2.S-457b	3.4-1, 109	A

Table 3.4.2-2, Condensate/Demineralized Water System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Piping, piping components	Pressure Boundary	Polymeric	Treated water	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	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.S-483b	3.4-1, 135	A
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Polymeric	Air	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	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-483a	3.4-1, 135	A
Piping, piping components, ducting, ducting components, seals	Pressure Boundary	Polymeric	Treated water	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	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-483a	3.4-1, 135	A
Tanks	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.E.SP-75	3.4-1, 012	A

Table 3.4.2-2, Condensate/Demineralized Water System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Tanks within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”	Pressure Boundary	Steel	Air	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.17)	VIII.E.SP-115	3.4-1, 030	B
Tanks within the scope of AMP XI.M29, “Outdoor and Large Atmospheric Metallic Storage Tanks”	Pressure Boundary	Steel	Treated water	Loss of material due to general (steel only), pitting, crevice corrosion, MIC (steel, stainless steel only)	Outdoor and Large Atmospheric Metallic Storage Tanks (B.2.1.17)	VIII.E.S-405	3.4-1, 062	B
Tanks	Pressure Boundary	Stainless steel	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.E.SP-162	3.4-1, 083	A

Table 3.4.2-2 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. While these components are designated as part of the Condensate/Demineralized Water System in BFN design documents, it is the raw water environment of the Raw Cooling Water System that contributes to the erosion of these heat exchanger tubesheets.
2. This GALL-SLR item reflects consideration of leakage from a flanged connection. However, this system does not contain any submerged closure bolting.
3. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.

Table 3.4.2-3, Reactor Feedwater System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	High-strength steel	Air - indoor uncontrolled	Cracking due to SCC	Bolting Integrity (B.2.1.10)	IV.C1.R-11	3.1-1, 062	A
Closure bolting	Mechanical Closure	Stainless steel	Air - indoor uncontrolled	Cracking due to SCC	Bolting Integrity (B.2.1.10)	IV.C1.R-11	3.1-1, 062	A
Closure bolting	Mechanical Closure	Stainless steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion, wear	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1-1, 063	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion, wear	Bolting Integrity (B.2.1.10)	IV.C1.RP-42	3.1-1, 063	A
Closure bolting	Mechanical Closure	Stainless steel	Air - indoor uncontrolled (external)	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1-1, 067	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled (external)	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	IV.C1.RP-43	3.1-1, 067	A
Closure bolting	Mechanical Closure	Stainless steel	Any	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4-1, 006	A, 1
Closure bolting	Mechanical Closure	Steel	Any	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4-1, 006	A, 1
Closure bolting	Mechanical Closure	High-strength steel	Air	Cracking due to SCC; cyclic loading	Bolting Integrity (B.2.1.10)	VIII.H.S-03	3.4-1, 007	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VIII.H.S-02	3.4-1, 009	A

Table 3.4.2-3, Reactor Feedwater System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	Stainless steel	Treated 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)	Bolting Integrity (B.2.1.10)	VIII.H.S-418	3.4-1, 070	A, 1
Closure bolting	Mechanical Closure	Steel	Treated 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)	Bolting Integrity (B.2.1.10)	VIII.H.S-418	3.4-1, 070	A, 1
Closure bolting	Mechanical Closure	Stainless steel	Air	Cracking due to SCC	Bolting Integrity (B.2.1.10)	VIII.H.S-421	3.4-1, 073	A
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4-1, 034	A
Heat exchanger components	Pressure Boundary	Steel with stainless steel cladding	Treated water >60°C (>140°F)	Cracking due to SCC	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VII.E3.AP-112	3.3-1, 020	E, 2
Heat exchanger components and tubes	Pressure Boundary	Stainless steel, nickel alloy	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.SP-80	3.4-1, 085	E, 2

Table 3.4.2-3, Reactor Feedwater System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Insulated piping, piping components, tanks	Pressure Boundary	Steel	Air	Loss of material due to general, pitting, crevice corrosion (steel only); cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-402a	3.4-1, 063	A
Insulated piping, piping components, tanks	Pressure Boundary	Stainless steel, nickel alloy	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VIII.H.S-451b	3.4-1, 103	A
Insulated piping, piping components, tanks	Pressure Boundary	Stainless steel	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VIII.H.S-452b	3.4-1, 104	A
Reactor coolant pressure boundary components: piping, piping components; other pressure retaining components with fatigue analyses	Pressure Boundary	Stainless steel	Reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A
Reactor coolant pressure boundary components: piping, piping components; other pressure retaining components with fatigue analyses	Pressure Boundary	Steel (with or without nickel alloy or stainless steel cladding)	Reactor coolant	Cumulative fatigue damage: cracking due to fatigue, cyclic loading	Section 4.3 “Metal Fatigue”	IV.C1.R-220	3.1-1, 006	A
Class 1 valve bodies and bonnets	Pressure Boundary	Cast austenitic stainless steel	Reactor coolant >250°C (>482°F)	Loss of fracture toughness due to thermal aging embrittlement	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	IV.C1.R-08	3.1-1, 038	A

Table 3.4.2-3, Reactor Feedwater System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Class 1 piping, fittings and branch connections < NPS 4	Pressure Boundary	Stainless steel	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), thermal, mechanical, vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, (B.2.1.1) Water Chemistry (B.2.1.2), and ASME Code Class 1 Small-bore Piping (B.2.1.22)	IV.C1.RP-230	3.1-1, 039	A
Class 1 piping, fittings and branch connections < NPS 4	Pressure Boundary	Steel (with or without nickel alloy or stainless steel cladding)	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), thermal, mechanical, vibratory loading	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, (B.2.1.1) Water Chemistry (B.2.1.2), and ASME Code Class 1 Small-bore Piping (B.2.1.22)	IV.C1.RP-230	3.1-1, 039	A
Piping, piping components	Pressure Boundary	Steel	Reactor coolant	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-23	3.1-1, 060	A
Reactor coolant pressure boundary components	Pressure Boundary	Stainless steel	Reactor coolant	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	IV.C1.RP-158	3.1-1, 079	A
Piping, piping components greater than or equal to 4 NPS	Pressure Boundary	Stainless steel	Reactor coolant	Cracking due to SCC, IGSCC	BWR Stress Corrosion Cracking, (B.2.1.5) and Water Chemistry (B.2.1.2)	IV.C1.R-20	3.1-1, 097	B
Piping, piping components	Pressure Boundary	Stainless steel	Reactor coolant	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-406	3.1-1, 110	A

Table 3.4.2-3, Reactor Feedwater System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Reactor coolant	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	IV.C1.R-406	3.1-1, 110	A
Reactor coolant system components: Components defined as ASME Section XI components (e.g., reactor coolant pressure boundary components, core support structure components, ASME Class 2 or 3 components, including associated pressure-retaining welds) not managed by other AMR line items in GALL-SLR Chapter IV	Mechanical Closure	Nickel alloy	Air	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, (B.2.1.1) and Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
Reactor coolant system components: Components defined as ASME Section XI components (e.g., reactor coolant pressure boundary components, core support structure components, ASME Class 2 or 3 components, including associated pressure-retaining welds) not managed by other AMR line items in GALL-SLR Chapter IV	Pressure Boundary	Stainless steel	Air	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, (B.2.1.1) and Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A

Table 3.4.2-3, Reactor Feedwater System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Reactor coolant system components: Components defined as ASME Section XI components (e.g., reactor coolant pressure boundary components, core support structure components, ASME Class 2 or 3 components, including associated pressure-retaining welds) not managed by other AMR line items in GALL-SLR Chapter IV	Pressure Boundary	Stainless Steel - CASS	Air	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, (B.2.1.1) and Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
Reactor coolant system components: Components defined as ASME Section XI components (e.g., reactor coolant pressure boundary components, core support structure components, ASME Class 2 or 3 components, including associated pressure-retaining welds) not managed by other AMR line items in GALL-SLR Chapter IV	Pressure Boundary	Steel	Air	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, (B.2.1.1) and Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A

Table 3.4.2-3, Reactor Feedwater System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Reactor coolant system components: Components defined as ASME Section XI components (e.g., reactor coolant pressure boundary components, core support structure components, ASME Class 2 or 3 components, including associated pressure-retaining welds) not managed by other AMR line items in GALL-SLR Chapter IV	Pressure Boundary	Steel	Treated water	Cracking due to SCC, IGSCC (stainless steel or nickel alloy components only), cyclic loading; loss of material due to general corrosion (steel only), pitting corrosion, crevice corrosion, wear	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, (B.2.1.1) and Water Chemistry (B.2.1.2) (water chemistry-related or corrosion-related aging effect mechanisms only)	IV.E.R-444	3.1-1, 114	A
Piping, piping components	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-431	3.1-1, 124	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-448	3.1-1, 133	A
Piping, piping components	Pressure Boundary	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	IV.C1.R-452a	3.1-1, 136	A
Piping, piping components	Pressure Boundary	Copper alloy	Air	None	None	IV.E.R-453	3.1-1, 137	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Cumulative fatigue damage due to fatigue	Section 4.3 “Metal Fatigue”	VIII.D2.S-11	3.4-1, 001	A
Piping, piping components, tanks	Pressure Boundary	Stainless steel	Air	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VIII.D2.SP-118a	3.4-1, 002	A
Piping, piping components	Pressure Boundary	Stainless steel	Air	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VIII.D2.SP-127a	3.4-1, 003	A

Table 3.4.2-3, Reactor Feedwater System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Steel	Treated water	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.D2.S-16	3.4-1, 005	A
Piping, piping components	Pressure Boundary	Stainless steel	Treated water >60°C (>140°F)	Cracking due to SCC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.E.SP-88	3.4-1, 011	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.D2.SP-73	3.4-1, 014	A
Piping, piping components	Pressure Boundary	Copper alloy	Air	None	None	VIII.I.SP-6	3.4-1, 054	A
Piping, piping components	Pressure Boundary	Stainless steel	Treated water	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.D2.S-408	3.4-1, 060	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.D2.S-408	3.4-1, 060	A
Piping, piping components	Pressure Boundary	Stainless steel	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.D2.SP-87	3.4-1, 085	A
Piping, piping components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Air	Cracking due to SCC	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-454	3.4-1, 106	A
Tanks	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.E.SP-75	3.4-1, 012	A

Table 3.4.2-3 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. This GALL-SLR item reflects consideration of leakage from a flanged connection. However, this system does not contain any submerged closure bolting.
2. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24) is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.

Table 3.4.2-4, Heater Drains and Vents System - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Closure bolting	Mechanical Closure	Steel	Any	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4-1, 006	A, 1
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VIII.H.S-02	3.4-1, 009	A
Closure bolting	Mechanical Closure	Steel	Treated 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)	Bolting Integrity (B.2.1.10)	VIII.H.S-418	3.4-1, 070	A, 1
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4-1, 034	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.D2.S-16	3.4-1, 005	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.D2.SP-73	3.4-1, 014	A
Piping, piping components	Pressure Boundary	Cast Iron	Treated water	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.D2.S-408	3.4-1, 060	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.D2.S-408	3.4-1, 060	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	VIII.D2.S-432	3.4-1, 081	A

Table 3.4.2-4 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. This GALL-SLR item reflects consideration of leakage from a flanged connection. However, this system does not contain any submerged closure bolting.

Table 3.4.2-5, Miscellaneous Turbine Connections System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	Steel	Any	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4-1, 006	A, 1
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VIII.H.S-02	3.4-1, 009	A
Closure bolting	Mechanical Closure	Steel	Treated 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)	Bolting Integrity (B.2.1.10)	VIII.H.S-418	3.4-1, 070	A, 1
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4-1, 034	A
Piping, piping components	Pressure Boundary	Steel	Steam	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.A.S-15	3.4-1, 005	A
Piping, piping components	Pressure Boundary	Steel	Steam	Loss of material due to general, pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.A.SP-71	3.4-1, 014	A
Piping, piping components	Pressure Boundary	Steel	Steam	Wall thinning due to erosion	Flow-Accelerated Corrosion (B.2.1.9)	VIII.A.S-408	3.4-1, 060	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	VIII.A.S-432	3.4-1, 081	A

Table 3.4.2-5 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. This GALL-SLR item reflects consideration of leakage from a flanged connection. However, this system does not contain any submerged closure bolting.

Table 3.4.2-6, Condenser Circulating Water System - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Closure bolting	Mechanical Closure	Steel	Any	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4-1, 006	A
Closure bolting	Mechanical Closure	Steel	Soil	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4-1, 006	A
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VIII.H.S-02	3.4-1, 009	A
Closure bolting	Mechanical Closure	Steel	Concrete	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	Buried and Underground Piping and Tanks (B.2.1.27)	VIII.H.SP-141	3.4-1, 050	B
Closure bolting	Mechanical Closure	Steel	Soil	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	Buried and Underground Piping and Tanks (B.2.1.27)	VIII.H.SP-141	3.4-1, 050	B
Closure bolting	Mechanical Closure	Steel	Raw 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)	Bolting Integrity (B.2.1.10)	VIII.H.S-418	3.4-1, 070	A
External surfaces	Pressure Boundary	Cast Iron and Cast Iron alloys	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4-1, 034	A
External surfaces	Pressure Boundary	Cast Iron and Cast Iron alloys	Condensation	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4-1, 034	A

Table 3.4.2-6, Condenser Circulating Water System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4-1, 034	A
External surfaces	Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4-1, 034	A
External surfaces	Pressure Boundary	Steel	Condensation	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4-1, 034	A
Heat exchanger tubes	Pressure Boundary, Heat Transfer	Copper alloy	Lubricating oil	Reduction of heat transfer due to fouling	Lubricating Oil Analysis (B.2.1.25) and One-Time Inspection (B.2.1.20)	VII.C1.A-791	3.3-1, 257	A, 1
Heat exchanger components (for components not covered by NRC GL 89-13)	Pressure Boundary	Stainless steel	Raw water	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.S-438	3.4-1, 091	A
Piping, piping components, tanks	Pressure Boundary	Stainless Steel	Air - indoor uncontrolled	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VIII.E.SP-118a	3.4-1, 002	A
Piping, piping components, tanks	Pressure Boundary	Stainless Steel	Air - outdoor	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VIII.E.SP-118a	3.4-1, 002	A
Piping, piping components, tanks	Pressure Boundary	Stainless Steel	Condensation	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VIII.E.SP-118a	3.4-1, 002	A
Piping, piping components	Pressure Boundary	Stainless steel	Air - indoor uncontrolled	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VIII.E.SP-127a	3.4-1, 003	A
Piping, piping components	Pressure Boundary	Stainless steel	Air - outdoor	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VIII.E.SP-127a	3.4-1, 003	A

Table 3.4.2-6, Condenser Circulating Water System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components	Pressure Boundary	Stainless steel	Condensation	Loss of material due to pitting, crevice corrosion	One-Time Inspection (B.2.1.20)	VIII.E.SP-127a	3.4-1, 003	A
Piping, piping components	Pressure Boundary	Steel	Condensation	Loss of material due to general, pitting, crevice corrosion	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.SP-60	3.4-1, 037	A
Piping, piping components	Pressure Boundary	Steel	Concrete	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	Buried and Underground Piping and Tanks (B.2.1.27)	VIII.H.SP-161	3.4-1, 050	B
Piping, piping components	Pressure Boundary	Steel	Soil	Loss of material due to general, pitting, crevice corrosion, MIC (soil only)	Buried and Underground Piping and Tanks (B.2.1.27)	VIII.H.SP-161	3.4-1, 050	B
Piping, piping components	Pressure Boundary	Steel	Concrete	None	None	VIII.I.SP-154	3.4-1, 051	A
Piping, piping components	Pressure Boundary	Copper alloy	Air	None	None	VIII.I.SP-6	3.4-1, 054	A
Piping, piping components	Pressure Boundary	Steel	Concrete	Cracking due to SCC (steel in carbonate/ bicarbonate environment only)	Buried and Underground Piping and Tanks (B.2.1.27)	VIII.H.S-420	3.4-1, 072	B
Piping, piping components	Pressure Boundary	Cast Iron and Cast Iron Alloy	Raw water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	VIII.E.S-432	3.4-1, 081	A
Piping, piping components	Pressure Boundary	Steel	Raw water	Long-term loss of material due to general corrosion	One-Time Inspection (B.2.1.20)	VIII.E.S-432	3.4-1, 081	A

Table 3.4.2-6, Condenser Circulating Water System - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Piping, piping components (for components not covered by NRC GL 89-13)	Pressure Boundary	Copper Alloy	Raw water	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.S-436	3.4-1, 089	A
Piping, piping components (for components not covered by NRC GL 89-13)	Pressure Boundary	Stainless Steel	Raw water	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.S-436	3.4-1, 089	A
Piping, piping components (for components not covered by NRC GL 89-13)	Pressure Boundary	Steel	Raw water	Loss of material due to general (steel, copper alloy only), pitting, crevice corrosion, MIC; flow blockage due to fouling	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.24)	VIII.E.S-436	3.4-1, 089	A

Table 3.4.2-6 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. Component is exposed to Condenser Circulating Water pump motor bearing lubricating oil.

Table 3.4.2-7, Gland Seal Water System - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Closure bolting	Mechanical Closure	Steel	Any	Loss of preload due to thermal effects, gasket creep, self-loosening	Bolting Integrity (B.2.1.10)	VIII.H.SP-142	3.4-1, 006	A, 1
Closure bolting	Mechanical Closure	Steel	Air - indoor uncontrolled	Loss of material due to general (steel only), pitting, crevice corrosion	Bolting Integrity (B.2.1.10)	VIII.H.S-02	3.4-1, 009	A
Closure bolting	Mechanical Closure	Steel	Treated 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)	Bolting Integrity (B.2.1.10)	VIII.H.S-418	3.4-1, 070	A, 1
External surfaces	Pressure Boundary	Cast Iron and Cast Iron Alloy	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4-1, 034	A
External surfaces	Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4-1, 034	A
Piping, piping components	Pressure Boundary	Cast Iron and Cast Iron Alloy	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.E.SP-73	3.4-1, 014	A
Piping, piping components	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.E.SP-73	3.4-1, 014	A
Piping, piping components	Pressure Boundary	Copper alloy	Treated water	Loss of material due to pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.A.SP-101	3.4-1, 016	A

Table 3.4.2-7, Gland Seal Water System - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Piping, piping components	Pressure Boundary	Gray cast iron	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VIII.E.SP-27	3.4-1, 033	A
Piping, piping components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Treated water	Loss of material due to selective leaching	Selective Leaching (B.2.1.21)	VIII.E.SP-55	3.4-1, 033	A
Piping, piping components	Pressure Boundary	Copper alloy	Air	None	None	VIII.I.SP-6	3.4-1, 054	A
Piping elements	Pressure Boundary	Glass	Air	None	None	VIII.I.SP-33	3.4-1, 055	A
Piping elements	Pressure Boundary	Glass	Treated water	None	None	VIII.I.SP-35	3.4-1, 055	A
Piping, piping components	Pressure Boundary	Copper alloy (>15% Zn or >8% Al)	Air	Cracking due to SCC	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-454	3.4-1, 106	A
Tanks	Pressure Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion, MIC	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VIII.E.SP-75	3.4-1, 012	A

Table 3.4.2-7 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. This GALL-SLR item reflects consideration of leakage from a flanged connection. However, this system does not contain any submerged closure bolting.

3.5 AGING MANAGEMENT OF CONTAINMENTS, 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, Scoping and Screening Results: Structures, 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 Buildings (2.4.1)
- Primary Containment Structures (2.4.2)
- Diesel Generator Buildings (2.4.3)
- Intake Pumping Station (2.4.4)
- Reinforced Concrete Chimney (2.4.5)
- Standby Gas Treatment Building (2.4.6)
- Off-Gas Treatment Building (2.4.7)
- Equipment Access Lock (2.4.8)
- Vacuum Pipe Building (2.4.9)
- Turbine Buildings (2.4.10)
- Radwaste Building (2.4.11)
- Service Building (2.4.12)
- Vent Vaults (2.4.13)
- Gate Structure Number 2 (2.4.14)
- Gate Structure Number 3 (2.4.15)
- Discharge Control Structure (2.4.16)
- Circulating Water Conduits (2.4.17)
- Diesel High Pressure Fire Pump House (2.4.18)
- Low Level Radwaste (LLRW) Storage Facility (2.4.19)
- Transformer Yard (2.4.20)
- 161 kV Switchyard (2.4.21)
- 500 kV Switchyard (2.4.22)
- Condensate Water Storage Tanks Foundations, Trenches, and Tunnels (2.4.23)
- Nitrogen Storage Tank Foundation (2.4.24)
- Supplemental Diesel Generator Building (2.4.25)
- Containment Atmosphere Dilution System Storage Tank Foundation (2.4.26)
- Intake Channel (2.4.27)
- North Bank of Cool Water Channel East of Gate Structure Number 2 (2.4.28)
- South Dike of Cool Water Channel between Gate Structures Number 2 and Number 3 (2.4.29)
- Earth Berm (2.4.30)
- Residual Heat Removal Service Water Tunnel (2.4.31)
- Electrical Cable Tunnel (from Intake Pumping Station to Powerhouse) (2.4.32)
- Underground Concrete Encased Structures (2.4.33)

- Yard, General (2.4.34)
- South Access Retaining Wall (2.4.35)
- Structural Commodities (2.4.36)
- Isolation Valve Pits (2.4.37)

3.5.2 Results

The following tables summarize the results of the aging management review for Containments, Structures, and Component Supports.

- Table 3.5.2-1, Reactor Buildings - Summary of Aging Management Evaluation
- Table 3.5.2-2, Primary Containment Structures - Summary of Aging Management Evaluation
- Table 3.5.2-3, Diesel Generator Buildings - Summary of Aging Management Evaluation
- Table 3.5.2-4, Intake Pumping Station - Summary of Aging Management Evaluation
- Table 3.5.2-5, Reinforced Concrete Chimney - Summary of Aging Management Evaluation
- Table 3.5.2-6, Standby Gas Treatment Building - Summary of Aging Management Evaluation
- Table 3.5.2-7, Off Gas Treatment Building - Summary of Aging Management Evaluation
- Table 3.5.2-8, Equipment Access Lock - Summary of Aging Management Evaluation
- Table 3.5.2-9, Vacuum Pipe Building - Summary of Aging Management Evaluation
- Table 3.5.2-10, Turbine Buildings - Summary of Aging Management Evaluation
- Table 3.5.2-11, Radwaste Building - Summary of Aging Management Evaluation
- Table 3.5.2-12, Service Building - Summary of Aging Management Evaluation
- Table 3.5.2-13, Vent Vaults - Summary of Aging Management Evaluation
- Table 3.5.2-14, Gate Structure Number 2 - Summary of Aging Management Evaluation
- Table 3.5.2-15, Gate Structure Number 3 - Summary of Aging Management Evaluation
- Table 3.5.2-16, Discharge Control Structure - Summary of Aging Management Evaluation
- Table 3.5.2-17, Circulating Water Conduits - Summary of Aging Management Evaluation
- Table 3.5.2-18, Diesel High Pressure Fire Pump House - Summary of Aging Management Evaluation
- Table 3.5.2-19, Low Level Radwaste (LLRW) Storage Facility - Summary of Aging Management Evaluation
- Table 3.5.2-20, Transformer Yard - Summary of Aging Management Evaluation
- Table 3.5.2-21, 161 kV Switchyard - Summary of Aging Management Evaluation
- Table 3.5.2-22, 500 kV Switchyard - Summary of Aging Management Evaluation
- Table 3.5.2-23, Condensate Water Storage Tanks Foundations, Trenches, and Tunnels - Summary of Aging Management Evaluation
- Table 3.5.2-24, Nitrogen Storage Tanks Foundation - Summary of Aging Management Evaluation
- Table 3.5.2-25, Supplemental Diesel Generator Building - Summary of Aging Management Evaluation
- Table 3.5.2-26, Containment Atmosphere Dilution System Storage Tank Foundation - Summary of Aging Management Evaluation

- Table 3.5.2-27, Intake Channel - Summary of Aging Management Evaluation
- Table 3.5.2-28, North Bank of Cool Water Channel East of Gate Structure Number 2- Summary of Aging Management Evaluation
- Table 3.5.2-29, South Dike of Cool Water Channel between Gate Structures Number 2 and Number 3 - Summary of Aging Management Evaluation
- Table 3.5.2-30, Earth Berm - Summary of Aging Management Evaluation
- Table 3.5.2-31, Residual Heat Removal Service Water Tunnel - Summary of Aging Management Evaluation
- Table 3.5.2-32, Electrical Cable Tunnel (from Intake Pumping Station to Powerhouse) - Summary of Aging Management Evaluation
- Table 3.5.2-33, Underground Concrete Encased Structures - Summary of Aging Management Evaluation
- Table 3.5.2-34, Yard, General - Summary of Aging Management Evaluation
- Table 3.5.2-35, South Access Retaining Wall - Summary of Aging Management Evaluation
- Table 3.5.2-36, Structural Commodities - Summary of Aging Management Evaluation
- Table 3.5.2-37, Isolation Valve Pits - Summary of Aging Management Evaluation

3.5.2.1 Materials, Environments, Aging Effects Requiring Management And Aging Management Programs

3.5.2.1.1 Reactor Buildings

Materials

The materials of construction for the Reactor Buildings components are:

- Aluminum
- Concrete
- Concrete Block
- Galvanized Steel
- Non-Ferrous Aluminum
- Polyurethane Foam
- Stainless Steel
- Steel

Environments

The Reactor Buildings components are exposed to the following environments:

- Air - indoor uncontrolled
- Air - outdoor
- Concrete
- Condensation
- Embedded/encased
- Groundwater
- Groundwater/soil

- Soil
- Treated Water
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Reactor Buildings components require management:

- Cracking
- Cracking; loss of bond; loss of material (spalling, scaling)
- Increase in porosity and permeability; cracking; 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 preload
- Radiation embrittlement; Hardening, loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the Reactor Buildings components:

- Masonry Walls (B.2.1.32)
- Structures Monitoring (B.2.1.33)
- TLAA (Section 4.7)
- Water Chemistry (B.2.1.2)
- One-Time Inspection (B.2.1.20)

3.5.2.1.2 Primary Containment Structures

Materials

The materials of construction for the Primary Containment Structures components are:

- Concrete
- Galvanized Steel
- Graphite
- Lubrite®
- Molykote® 321 or equal
- Service Level I Coatings
- Stainless steel
- Stainless Steel; Dissimilar Metal Welds
- Steel

Environments

The Primary Containment Structures components are exposed to the following environments:

- Air - indoor uncontrolled

- Concrete
- Treated Water

Aging Effects Requiring Management

The following aging effects associated with the Primary Containment Structures components require management:

- Cracking
- Cracking; loss of bond; and loss of material (spalling, scaling)
- Cumulative fatigue damage
- Increase in porosity and permeability; cracking; loss of material (spalling, scaling)
- Loss of coating or lining integrity
- Loss of leak tightness
- Loss of material
- Loss of mechanical function
- Loss of preload
- Reduction in strength; loss of mechanical properties

Aging Management Programs

The following aging management programs manage the aging effects for the Primary Containment Structures components:

- 10 CFR Part 50, Appendix J (B.2.1.31)
- ASME Section XI, Subsection IWE (B.2.1.29)
- ASME Section XI, Subsection IWF (B.2.1.30)
- TLAA (Section 4.3)
- TLAA (Section 4.6)
- Protective Coating Monitoring and Maintenance (B.2.1.35)
- Structures Monitoring (B.2.1.33)
- One-Time Inspection (B.2.1.20)

3.5.2.1.3 Diesel Generator Buildings

Materials

The materials of construction for the Diesel Generator Buildings components are:

- Concrete
- Concrete Block
- Galvanized Steel
- Steel

Environments

The Diesel Generator Buildings components are exposed to the following environments:

- Air - indoor uncontrolled
- Air - outdoor

- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Diesel Generator Buildings components require management:

- Cracking
- Cracking and distortion
- Cracking; loss of bond; loss of material (spalling, scaling)
- Increase in porosity and permeability; cracking; 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 preload

Aging Management Programs

The following aging management programs manage the aging effects for the Diesel Generator Buildings components:

- Masonry Walls (B.2.1.32)
- Structures Monitoring (B.2.1.33)

3.5.2.1.4 Intake Pumping Station

Materials

The materials of construction for the Intake Pumping Station components are:

- Concrete
- Concrete Block
- Galvanized Steel
- Steel

Environments

The Intake Pumping Station components are exposed to the following environments:

- Air - indoor uncontrolled
- Air - outdoor
- Groundwater
- Groundwater/soil
- Soil
- Water - flowing
- Water - standing

Aging Effects Requiring Management

The following aging effects associated with the Intake Pumping Station components require management:

- Cracking
- Cracking; loss of bond; loss of material (spalling, scaling)
- Increase in porosity and permeability; cracking; 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 preload

Aging Management Programs

The following aging management programs manage the aging effects for the Intake Pumping Station components:

- Inspection of Water-Control Structures associated with Nuclear Power Plants (B.2.1.34)
- Masonry Walls (B.2.1.32)
- Structures Monitoring (B.2.1.33)

3.5.2.1.5 Reinforced Concrete Chimney

Materials

The materials of construction for the Reinforced Concrete Chimney components are:

- Concrete
- Concrete Block
- Galvanized Steel
- Steel

Environments

The Reinforced Concrete Chimney components are exposed to the following environments:

- Air - indoor uncontrolled
- Air - outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Reinforced Concrete Chimney components require management:

- Cracking
- Cracking; loss of bond; loss of material (spalling, scaling)
- Increase in porosity and permeability; loss of strength

- Increase in porosity and permeability; cracking; loss of material (spalling, scaling)
- Loss of material
- Loss of material (spalling, scaling) and cracking
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the Reinforced Concrete Chimney components:

- Masonry Walls (B.2.1.32)
- Structures Monitoring (B.2.1.33)

3.5.2.1.6 Standby Gas Treatment Building

Materials

The materials of construction for the Standby Gas Treatment Building components are:

- Concrete

Environments

The Standby Gas Treatment Building components are exposed to the following environments:

- Air - indoor uncontrolled
- Air - outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Standby Gas Treatment Building components require management:

- Cracking
- Cracking and distortion
- Cracking; loss of bond; loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Increase in porosity and permeability; cracking; loss of material (spalling, scaling)
- Increase in porosity and permeability; loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the Standby Gas Treatment Building components:

- Structures Monitoring (B.2.1.33)

3.5.2.1.7 Off-Gas Treatment Building

Materials

The materials of construction for the Off-Gas Treatment Building components are:
- Concrete
- Concrete Block

Environments

The Off-Gas Treatment Building components are exposed to the following environments:
- Air - indoor uncontrolled
- Air - outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Off-Gas Treatment Building components require management:
- Cracking
- Cracking; loss of bond; loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Increase in porosity and permeability; cracking; loss of material (spalling, scaling)
- Increase in porosity and permeability; loss of strength

Aging Management Programs

The following aging management programs manage the aging effects for the Off-Gas Treatment Building components:
- Masonry Walls (B.2.1.32)
- Structures Monitoring (B.2.1.33)

3.5.2.1.8 Equipment Access Lock

Materials

The materials of construction for the Equipment Access Lock components are:
- Concrete
- Galvanized Steel
- Steel

Environments

The Equipment Access Lock components are exposed to the following environments:
- Air - indoor uncontrolled
- Air - outdoor

- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Equipment Access Lock components require management:

- Cracking
- Cracking; loss of bond; loss of material (spalling, scaling)
- 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
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the Equipment Access Lock components:

- Structures Monitoring (B.2.1.33)

3.5.2.1.9 Vacuum Pipe Building

Materials

The materials of construction for the Vacuum Pipe Building components are:

- Concrete

Environments

The Vacuum Pipe Building components are exposed to the following environments:

- Air - indoor uncontrolled
- Air - outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Vacuum Pipe Building components require management:

- Cracking
- Cracking and distortion
- Cracking; loss of bond; loss of material (spalling, scaling)
- 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

Aging Management Programs

The following aging management programs manage the aging effects for the Vacuum Pipe Building components:

- Structures Monitoring (B.2.1.33)

3.5.2.1.10 Turbine Buildings

Materials

The materials of construction for the Turbine Buildings components are:

- Concrete
- Concrete Block
- Galvanized Steel
- Steel

Environments

The Turbine Buildings components are exposed to the following environments:

- Air - indoor uncontrolled
- Air - outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Turbine Buildings components require management:

- Cracking
- Cracking; loss of bond; loss of material (spalling, scaling)
- 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
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the Turbine Buildings components:

- Masonry Walls (B.2.1.32)
- Structures Monitoring (B.2.1.33)

3.5.2.1.11 Radwaste Building

Materials

The materials of construction for the Radwaste Building components are:

- Aluminum
- Concrete
- Concrete Block
- Galvanized Steel
- Steel

Environments

The Radwaste Building components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air - outdoor
- Condensation
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Radwaste Building components require management:

- Cracking
- Cracking; loss of bond; loss of material (spalling, scaling)
- 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
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the Radwaste Building components:

- Masonry Walls (B.2.1.32)
- One-Time Inspection (B.2.1.20)
- Structures Monitoring (B.2.1.33)

3.5.2.1.12 Service Building

Materials

The materials of construction for the Service Building components are:

- Concrete
- Concrete Block
- Galvanized Steel
- Steel

Environments

The Service Building components are exposed to the following environments:

- Air - indoor uncontrolled
- Air - outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Service Building components require management:

- Cracking
- Cracking and distortion
- Cracking; loss of bond; loss of material (spalling, scaling)
- 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
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the Service Building components:

- Masonry Walls (B.2.1.32)
- Structures Monitoring (B.2.1.33)

3.5.2.1.13 Vent Vaults

Materials

The materials of construction for the Vent Vaults components are:

- Concrete

Environments

The Vent Vaults components are exposed to the following environments:

- Air - indoor uncontrolled
- Air - outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Vent Vaults components require management:

- Cracking
- Cracking and distortion
- Cracking; loss of bond; loss of material (spalling, scaling)
- 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

Aging Management Programs

The following aging management programs manage the aging effects for the Vent Vaults components:

- Structures Monitoring (B.2.1.33)

3.5.2.1.14 Gate Structure Number 2

Materials

The materials of construction for the Gate Structure Number 2 components are:

- Concrete
- Steel

Environments

The Gate Structure Number 2 components are exposed to the following environments:

- Air - outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Gate Structure Number 2 components require management:

- Cracking
- Cracking; loss of bond; loss of material (spalling, scaling)

- 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
- Loss of material

Aging Management Programs

The following aging management programs manage the aging effects for the Gate Structure Number 2 components:

- Inspection of Water-Control Structures associated with Nuclear Power Plants (B.2.1.34)
- Structures Monitoring (B.2.1.33)

3.5.2.1.15 Gate Structure Number 3

Materials

The materials of construction for the Gate Structure Number 3 components are:

- Concrete
- Steel

Environments

The Gate Structure Number 3 components are exposed to the following environments:

- Air - outdoor
- Concrete
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Gate Structure Number 3 components require management:

- Cracking
- Cracking; loss of bond; loss of material (spalling, scaling)
- 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
- Loss of material
- Loss of preload

Aging Management Programs

The following aging management programs manage the aging effects for the Gate Structure Number 3 components:

- Inspection of Water-Control Structures associated with Nuclear Power Plants (B.2.1.34)
- Structures Monitoring (B.2.1.33)

3.5.2.1.16 Discharge Control Structure

Materials

The materials of construction for the Discharge Control Structure components are:
- Concrete

Environments

The Discharge Control Structure components are exposed to the following environments:
- Air - outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Discharge Control Structure components require management:
- Cracking
- Cracking; loss of bond; loss of material (spalling, scaling)
- 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
- Loss of material

Aging Management Programs

The following aging management programs manage the aging effects for the Discharge Control Structure components:
- Inspection of Water-Control Structures associated with Nuclear Power Plants (B.2.1.34)
- Structures Monitoring (B.2.1.33)

3.5.2.1.17 Circulating Water Conduits

Materials

The materials of construction for the Circulating Water Conduits components are:
- Concrete
- Concrete, concrete cylinder piping, reinforced concrete
- Steel

Environments

The Circulating Water Conduits components are exposed to the following environments:
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Circulating Water Conduits components require management:

- Cracking
- Cracking and distortion
- Cracking; loss of bond; loss of material (spalling, scaling)
- Increase in porosity and permeability; cracking; loss of material (spalling, scaling)
- Increase in porosity and permeability; loss of strength
- Loss of material

Aging Management Programs

The following aging management programs manage the aging effects for the Circulating Water Conduits components:

- Inspection of Water-Control Structures associated with Nuclear Power Plants (B.2.1.34)
- Structures Monitoring (B.2.1.33)

3.5.2.1.18 Diesel High Pressure Fire Pump House

Materials

The materials of construction for the Diesel High Pressure Fire Pump House components are:

- Concrete
- Galvanized Steel
- Steel

Environments

The Diesel High Pressure Fire Pump House components are exposed to the following environments:

- Air - indoor uncontrolled
- Air - outdoor
- Raw or Treated Water
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Diesel High Pressure Fire Pump House components require management:

- Cracking
- Cracking; loss of bond; loss of material (spalling, scaling)
- Increase in porosity and permeability; cracking; 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 preload

Aging Management Programs

The following aging management programs manage the aging effects for the Diesel High Pressure Fire Pump House components:

- Structures Monitoring (B.2.1.33)

3.5.2.1.19 Low Level Radwaste (LLRW) Storage Facility

Materials

The materials of construction for the LLRW Storage Facility components are:

- Concrete
- Galvanized Steel
- Steel

Environments

The LLRW Storage Facility components are exposed to the following environments:

- Air - indoor uncontrolled
- Air - outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the LLRW Storage Facility components require management:

- Cracking
- Cracking and distortion
- Cracking; loss of bond; loss of material (spalling, scaling)
- Increase in porosity and permeability; cracking; 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 preload

Aging Management Programs

The following aging management programs manage the aging effects for the LLRW Storage Facility components:

- Structures Monitoring (B.2.1.33)

3.5.2.1.20 Transformer Yard

Materials

The materials of construction for the Transformer Yard components are:

- Concrete
- Galvanized Steel
- Steel

Environments

The Transformer Yard components are exposed to the following environments:

- Air - outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Transformer Yard components require management:

- Cracking
- Cracking and distortion
- Cracking; loss of bond; loss of material (spalling, scaling)
- Increase in porosity and permeability; cracking; 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 preload

Aging Management Programs

The following aging management programs manage the aging effects for the Transformer Yard components:

- Structures Monitoring (B.2.1.33)

3.5.2.1.21 161 kV Switchyard

Materials

The materials of construction for the 161 kV Switchyard components are:

- Concrete
- Galvanized Steel
- Steel

Environments

The 161 kV Switchyard components are exposed to the following environments:

- Air - indoor uncontrolled
- Air - outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the 161 kV Switchyard components require management:

- Cracking
- Cracking and distortion
- Cracking; loss of bond; loss of material (spalling, scaling)
- Increase in porosity and permeability; cracking; 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 preload

Aging Management Programs

The following aging management programs manage the aging effects for the 161 kV Switchyard components:

- Structures Monitoring (B.2.1.33)

3.5.2.1.22 500 kV Switchyard

Materials

The materials of construction for the 500 kV Switchyard components are:

- Concrete
- Galvanized Steel
- Steel

Environments

The 500 kV Switchyard components are exposed to the following environments:

- Air - indoor uncontrolled
- Air - outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the 500 kV Switchyard components require management:

- Cracking
- Cracking and distortion
- Cracking; loss of bond; loss of material (spalling, scaling)
- Increase in porosity and permeability; cracking; 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 preload

Aging Management Programs

The following aging management programs manage the aging effects for the 500 kV Switchyard components:

- Structures Monitoring (B.2.1.33)

3.5.2.1.23 Condensate Water Storage Tanks Foundations, Trenches, and Tunnels

Materials

The materials of construction for the Condensate Water Storage Tanks Foundations, Trenches, and Tunnels components are:

- Concrete
- Earthfill (rock and sand)
- Galvanized Steel
- Steel

Environments

The Condensate Water Storage Tanks Foundations, Trenches, and Tunnels components are exposed to the following environments:

- Air - indoor uncontrolled
- Air - outdoor
- Groundwater/soil
- Soil
- Water - flowing
- Water - standing

Aging Effects Requiring Management

The following aging effects associated with the Condensate Water Storage Tanks Foundations, Trenches, and Tunnels components require management:

- Cracking
- Cracking and distortion

- Cracking; loss of bond; loss of material (spalling, scaling)
- Increase in porosity and permeability; cracking; 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 preload

Aging Management Programs

The following aging management programs manage the aging effects for the Condensate Water Storage Tanks Foundations, Trenches, and Tunnels components:

- Structures Monitoring (B.2.1.33)

3.5.2.1.24 Nitrogen Storage Tank Foundation

Materials

The materials of construction for the Nitrogen Storage Tank Foundation components are:

- Concrete

Environments

The Nitrogen Storage Tank Foundation components are exposed to the following environments:

- Air - outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Nitrogen Storage Tank Foundation components require management:

- Cracking
- Cracking and distortion
- Cracking; loss of bond; loss of material (spalling, scaling)
- 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

Aging Management Programs

The following aging management programs manage the aging effects for the Nitrogen Storage Tank Foundation components:

- Structures Monitoring (B.2.1.33)

3.5.2.1.25 Supplemental Diesel Generator Building

Materials

The materials of construction for the Supplemental Diesel Generator Building components are:

- Concrete
- Galvanized Steel
- Steel

Environments

The Supplemental Diesel Generator Building components are exposed to the following environments:

- Air - indoor uncontrolled
- Air - outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Supplemental Diesel Generator Building components require management:

- Cracking
- Cracking and distortion
- Cracking; loss of bond; loss of material (spalling, scaling)
- Increase in porosity and permeability; cracking; 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 preload

Aging Management Programs

The following aging management programs manage the aging effects for the Supplemental Diesel Generator Building components:

- Structures Monitoring (B.2.1.33)

3.5.2.1.26 Containment Atmosphere Dilution System Storage Tank Foundation

Materials

The materials of construction for the Containment Atmosphere Dilution System Storage Tank Foundation components are:

- Concrete

Environments

The Containment Atmosphere Dilution System Storage Tank Foundation components are exposed to the following environments:

- Air - outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Containment Atmosphere Dilution System Storage Tank Foundation components require management:

- Cracking
- Cracking and distortion
- Cracking; loss of bond; loss of material (spalling, scaling)
- 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

Aging Management Programs

The following aging management programs manage the aging effects for the Containment Atmosphere Dilution System Storage Tank Foundation components:

- Structures Monitoring (B.2.1.33)

3.5.2.1.27 Intake Channel

Materials

The materials of construction for the Intake Channel components are:

- Earthfill (Clay and In-situ Soil)

Environments

The Intake Channel components are exposed to the following environments:

- Air - outdoor
- Soil
- Water - flowing
- Water - standing

Aging Effects Requiring Management

The following aging effects associated with the Intake Channel components require management:

- Loss of material; loss of form

Aging Management Programs

The following aging management programs manage the aging effects for the Intake Channel components:

- Inspection of Water-Control Structures associated with Nuclear Power Plants (B.2.1.34)

3.5.2.1.28 North Bank of Cool Water Channel East of Gate Structure Number 2

Materials

The materials of construction for the North Bank of Cool Water Channel East of Gate Structure Number 2 components are:

- Earthfill (Clay and In-situ Soil)

Environments

The North Bank of Cool Water Channel East of Gate Structure Number 2 components are exposed to the following environments:

- Air - outdoor
- Soil
- Water - flowing
- Water - standing

Aging Effects Requiring Management

The following aging effects associated with the North Bank of Cool Water Channel East of Gate Structure Number 2 components require management:

- Loss of material; loss of form

Aging Management Programs

The following aging management programs manage the aging effects for the North Bank of Cool Water Channel East of Gate Structure Number 2 components:

- Inspection of Water-Control Structures associated with Nuclear Power Plants (B.2.1.34)

3.5.2.1.29 South Dike of Cool Water Channel between Gate Structures Number 2 and Number 3

Materials

The materials of construction for the South Dike of Cool Water Channel between Gate Structures Number 2 and Number 3 components are:

- Earthfill (Clay and In-situ Soil)

Environments

The South Dike of Cool Water Channel between Gate Structures Number 2 and Number 3 components are exposed to the following environments:

- Air - outdoor
- Soil

- Water - flowing
- Water - standing

Aging Effects Requiring Management

The following aging effects associated with the South Dike of Cool Water Channel between Gate Structures Number 2 and Number 3 components require management:

- Loss of material; loss of form

Aging Management Programs

The following aging management programs manage the aging effects for the South Dike of Cool Water Channel between Gate Structures Number 2 and Number 3 components:

- Inspection of Water-Control Structures associated with Nuclear Power Plants (B.2.1.34)

3.5.2.1.30 Earth Berm

Materials

The materials of construction for the Earth Berm components are:

- Rock and Earthfill

Environments

The Earth Berm components are exposed to the following environments:

- Air - outdoor
- Groundwater/soil

Aging Effects Requiring Management

The following aging effects associated with the Earth Berm components require management:

- Loss of material; loss of form

Aging Management Programs

The following aging management programs manage the aging effects for the Earth Berm components:

- Structures Monitoring (B.2.1.33)

3.5.2.1.31 Residual Heat Removal Service Water Tunnel

Materials

The materials of construction for the Residual Heat Removal Service Water Tunnel components are:

- Concrete
- Galvanized Steel
- Steel

Environments

The Residual Heat Removal Service Water Tunnel components are exposed to the following environments:

- Air - indoor uncontrolled
- Air - outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Residual Heat Removal Service Water Tunnel components require management:

- Cracking
- Cracking; loss of bond; loss of material (spalling, scaling)
- Increase in porosity and permeability; cracking; 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 preload

Aging Management Programs

The following aging management programs manage the aging effects for the Residual Heat Removal Service Water Tunnel components:

- Structures Monitoring (B.2.1.33)

3.5.2.1.32 Electrical Cable Tunnel (from Intake Pumping Station to Powerhouse)

Materials

The materials of construction for the Electrical Cable Tunnel (from Intake Pumping Station to Powerhouse) components are:

- Concrete

Environments

The Electrical Cable Tunnel (from Intake Pumping Station to Powerhouse) components are exposed to the following environments:

- Air - indoor uncontrolled
- Air - outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Electrical Cable Tunnel (from Intake Pumping Station to Powerhouse) components require management:

- Cracking
- Cracking and distortion
- Cracking; loss of bond; loss of material (spalling, scaling)
- 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

Aging Management Programs

The following aging management programs manage the aging effects for the Electrical Cable Tunnel (from Intake Pumping Station to Powerhouse) components:

- Structures Monitoring (B.2.1.33)

3.5.2.1.33 Underground Concrete Encased Structures

Materials

The materials of construction for the Underground Concrete Encased Structures components are:

- Concrete
- Steel

Environments

The Underground Concrete Encased Structures components are exposed to the following environments:

- Air - indoor uncontrolled
- Air - outdoor
- Concrete
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Underground Concrete Encased Structures components require management:

- Cracking
- Cracking and distortion
- Cracking; loss of bond; loss of material (spalling, scaling)
- Increase in porosity and permeability; cracking; loss of material (spalling, scaling)
- Increase in porosity and permeability; loss of strength

- Loss of material
- Loss of material (spalling, scaling) and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the Underground Concrete Encased Structures components:

- Structures Monitoring (B.2.1.33)

3.5.2.1.34 Yard Structures, General

Materials

The materials of construction for the Yard Structures, General components are:

- Concrete

Environments

The Yard Structures, General components are exposed to the following environments:

- Air - outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Yard Structures, General components require management:

- Cracking
- Cracking and distortion
- Cracking; loss of bond; loss of material (spalling, scaling)
- 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

Aging Management Programs

The following aging management programs manage the aging effects for the Yard Structures, General components:

- Structures Monitoring (B.2.1.33)

3.5.2.1.35 South Access Retaining Wall

Materials

The materials of construction for the South Access Retaining Wall components are:

- Concrete

Environments

The South Access Retaining Wall components are exposed to the following environments:

- Air - outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the South Access Retaining Wall components require management:

- Cracking
- Cracking and distortion
- Cracking; loss of bond; loss of material (spalling, scaling)
- 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

Aging Management Programs

The following aging management programs manage the aging effects for the South Access Retaining Wall components:

- Structures Monitoring (B.2.1.33)

3.5.2.1.36 Structural Commodities

Materials

The materials of construction for the Structural Commodities components are:

- Aluminum
- Asbestos
- Asphalt coating
- Calcium silicate
- Canvas
- Cast Iron and Cast Iron Alloys
- Cellular elastomeric
- Cement
- Cementitious coatings (Flamemastic, and other similar materials)
- Ceramic Fiber
- Cloth fabric
- Coatings (ALBI CLAD-161)
- Concrete
- Corkmastic
- Elastomer

- Fabricell
- Fiberglass
- Fluorogold
- Foam plastic
- Foil
- Galvanized steel
- Glass
- Glass fabric
- Graphitic tool steel
- Grout
- Gypsum
- High-strength steel
- Kraft
- Lead blankets (SS Mesh)
- Lubrite®
- Lubrofluor
- Masonry Walls
- Metal reflective
- Mineral wool
- Non-ferrous - aluminum
- Non-ferrous - copper alloys
- Non-metallic (e.g., rubber)
- Permali
- Polymer
- PVC tape
- Membrane (asphalt impregnated membrane water seal)
- Silicates (Marinite® or other similar materials)
- Stainless Steel
- Stainless Steel; Dissimilar metal welds
- Steel
- Steel; Dissimilar Metal Welds
- Subliming compounds (Thermolag ®)
- Vinyl Plastic
- Wire Fabric/Mesh

Environments

The Structural Commodities components are exposed to the following environments:

- Air
- Air - indoor uncontrolled
- Air - outdoor
- Condensation

- Concrete
- Groundwater/soil
- Raw Water
- Treated Water
- Underground
- Water - flowing
- Water - standing

Aging Effects Requiring Management

The following aging effects associated with the Structural Commodities components require management:

- Cracking
- Cracking; loss of material
- Cracking; loss of material (spalling, scaling) and cracking
- Cumulative fatigue damage
- Hardening or loss of strength; loss of material; cracking or blistering
- Hardening, loss of strength, shrinkage
- Loss of leak tightness
- Loss of leak tightness in closed position
- Loss of material
- Loss of material; cracking; hardening, loss of strength, shrinkage
- Loss of material; cracking/ delamination; change in material properties; separation
- Loss of mechanical function
- Loss of preload
- Loss of sealing
- Loss of weatherproofing integrity
- Reduction in concrete anchor capacity
- Reduction or loss of isolation function
- Reduced thermal insulation resistance
- SS mesh cracking, decomposition

Aging Management Programs

The following aging management programs manage the aging effects for the Structural Commodities components:

- 10 CFR Part 50, Appendix J (B.2.1.31)
- ASME Section XI, Subsection IWE (B.2.1.29)
- ASME Section XI, Subsection IWF (B.2.1.30)
- External Surfaces Monitoring of Mechanical Components (B.2.1.23)
- Fire Protection (B.2.1.15)
- Inspection of Water-Control Structures associated with Nuclear Power Plants (B.2.1.34)
- Masonry Walls (B.2.1.32)

- One-Time Inspection (B.2.1.20)
- Structures Monitoring (B.2.1.33)
- Water Chemistry (B.2.1.2)

3.5.2.1.37 Isolation Valve Pits

Materials

The materials of construction for the Isolation Valve Pits components are:
- Concrete
- Galvanized Steel
- Steel

Environments

The Isolation Valve Pits components are exposed to the following environments:
- Air - indoor uncontrolled
- Air - outdoor
- Groundwater/soil
- Soil
- Water - flowing

Aging Effects Requiring Management

The following aging effects associated with the Isolation Valve Pits components require management:
- Cracking
- Cracking and distortion
- Cracking; loss of bond; loss of material (spalling, scaling)
- Increase in porosity and permeability; cracking; 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 preload

Aging Management Programs

The following aging management programs manage the aging effects for the Isolation Valve Pits components:
- Structures Monitoring (B.2.1.33)

3.5.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL-SLR Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the subsequent license renewal application. For the Containments, Structures and Component Supports, those programs are addressed in the following subsections.

3.5.2.2.1 Pressurized Water Reactor and Boiling Water Reactor Containments

3.5.2.2.1.1 Cracking and Distortion Due to Increased Stress Levels from Settlement; Reduction of Foundation Strength, and Cracking Due to Differential Settlement and Erosion of Porous Concrete 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.

Table 3.5.1 Item Number 3.5-1, 001: This item does not apply to the BFN Mark I steel containments. The BFN containments are supported on reinforced concrete and are enclosed in reinforced concrete. The BFN suppression chambers are supported on steel supporting members which transmit loads to the reinforced foundation of the Reactor Building as described by FSAR Section 5.2 and shown on FSAR Figure 5.2-1a. The containment types described in this Item Number do not exist at BFN, the ASME Code Section XI, Subsection IWL is not applicable at BFN.

Table 3.5.1 Item Number 3.5-1, 002: This item is not applicable to the BFN Mark I steel containments, which are supported on the Reactor Building foundation, for which the design incorporates concrete in the sub-foundation. The design originally was supported by a steel skirt, reinforced by filling the internal cavity of the skirt with concrete, and vibrated to fill all voids. The skirt was later cut loose and the drywell now sits on a concrete pillar. BFN does not incorporate porous concrete in its subfoundation. Therefore, the causal factor of erosion of porous concrete utilized for the foundation or subfoundation is not applicable and requires no further consideration nor aging management. For components at BFN that are managed for settlement, the aging management program, Structures Monitoring program (B.2.1.33), will be used to manage cracks and distortion due to increased stress level from settlement; however, this aging mechanism is insignificant for the BFN Reactor Building structures because the structures are founded on bedrock as described in FSAR Sections 12.2 and 2.5. Cracking and distortion due to settlement has not been identified in BFN power block concrete structures. The condition of accessible and above grade reactor building concrete is used as an indicator for the condition of the inaccessible and below grade structural components and provides reasonable assurance that degradation of inaccessible structural components will be detected before a loss of an intended function. Cracks extending into accessible areas, if any, will be managed by the Structures Monitoring program (B.2.1.33). In the event that unacceptable conditions due to this mechanism are identified in the accessible areas of structures, procedures require that extent of condition be determined and additional inspections or evaluations, would address inaccessible and below grade portions of the structure. Reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete sub-foundation is not applicable because porous concrete is not used in the foundation design. This is validated from the termination of BFN dewatering system operation in 1983, due to no evidence of soil voids associated with the pumping ever manifesting. With no noted history for settlement since the termination, no additional considerations need be made. Since the settlement proceeds at a comparatively slow rate, the required five-year inspection frequency and scope of the Structures Monitoring program (B.2.1.33) are determined to be adequate. These programs address the monitoring for and evaluation of any signification concrete damage due to settlement before it can cause a loss of intended function.

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 any portions of the concrete containment components that 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. 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).

<u>Table 3.5.1 Item Number 3.5-1, 003:</u> This item is not applicable to the BFN Mark I steel containments. The components for this Item Number are concrete containment components. BFN Technical Specification 3.6.1.4 limits the drywell average air temperature to be less than 150°F. Each drywell is cooled during normal operation of the unit by a closed loop ventilation system designed to hold the average temperature in the drywell to ≤ 150°F. The normal drywell environment is described in FSAR Sections 5.2.3.2 and 5.2.3.7 as an average temperature of 150 degrees Fahrenheit or lower. Furthermore, regarding maintenance of local temperature limit (200°F), insulation and air gaps are provided to reduce thermal stress. Therefore, the concrete structural components located inside the drywell are not subject to general area temperature greater than 150°F or local area concrete temperature greater than 200°F. A review has confirmed that plant operating experience has not identified elevated general area and local area temperature as a concern for concrete structural components. The potential for gamma radiation induced heating in the sacrificial shield wall is addressed in EPRI Report 3002002676, Revision 0, February 2014, "Expected Condition of Reactor Cavity Concrete After 80 Years of Radiation Exposure," which concludes that the gamma dose for BWR plants will be no higher than the gamma dose for PWR plants. EPRI Report 3002008129, Revision 0, December 2016, "Long-Term Operations: Impact of Radiation Heating on PWR Biological Shield Concrete," evaluates the impact of radiation induced heating on bounding PWR plants. The evaluation determined that the localized temperature rise in the shield wall resulted in a localized concrete temperature of less than 180°F. The configuration of the BFN sacrificial shield wall, which is

described in FSAR Section 12.2.2.6, Figure 12.2-23, and Figure 12.2-27A, reflects the configuration shown in EPRI Report 3002002676, Figure 7.6, for the wall described (in the figure) as a biological shield.

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).*

   <u>Table 3.5.1 Item Numbers 3.5.1, 004 and 3.5.1, 005:</u> These Item Numbers are not applicable to the BFN Mark I steel containments. This Item is applicable instead to Mark II and Mark III containments. However, Item Number 3.5-1, 035 is applicable to BFN. The ASME Section XI, Subsection IWE program and the 10 CFR Part 50, Appendix J program will be used to manage the loss of material of steel elements in the accessible and inaccessible areas of the containment liner (which includes integral attachments), penetration sleeves, drywell shell, drywell head, drywell shell in the sand pocket regions, and embedded shell exposed to air-indoor. The majority of the ASME Section XI, Subsection IWE steel components, including the drywell head, are accessible for inspection. Preventive actions associated with Mark I steel containments as addressed by the ASME Section XI, Subsection IWE program (B.2.1.29) and 10 CFR Appendix J program (B.2.1.31), including components associated with sand pockets and sand pocket area drains, are applicable to the BFN Mark I Steel containments.

   The BFN primary containment design includes an accessible moisture barrier at the bottom floor inside of the drywell and includes an inaccessible sheet metal cover and joint sealing compound above the sand pocket region on the exterior of the drywell shell. The ASME Section XI, Subsection IWE program performs an examination of the accessible moisture barriers at the interior concrete to shell interface for wear, damage, erosion, tears, cracks, or other defects that may violate the leak-tight integrity. The examination of moisture barriers is intended to prevent intrusion of moisture into inaccessible areas of the pressure retaining metal containment shell. There has been no corrosion detected at the moisture barrier at the bottom of the drywell interior. However, for BFN Unit 2, Notice of Indication (NOI) U2R19-001 identified the following pitting and mechanical damage that required Engineering Evaluation: Bay 2 - 31.3 mils, Bay 3 - 125 mils, and Bay 8 - 31.3 mils. Examinations completed during Unit 2 refueling outages U2R20 and U2R21 documented that the degradation in these areas was essentially unchanged and these locations no longer require Augmented Examination.

   Additionally, BFN Units 1, 2, and 3 Mark I steel primary containment design is subject to corrosion and generalized wasting at the sand bed region (SBR) as identified in NRC Generic Letter (GL) 87-05. The generic letter documented wall thinning at the sand bed region at Oyster Creek Generating Station that resulted from significant material wasting of the carbon steel plates from corrosion with potential to impair operability of containment. The activities performed by BFN to monitor and maintain the condition of drywell shell in the sand bed region as well as the sand bed drains have been reviewed and documented to support this further evaluation. This included a review of associated documentation of this issue since 1980, BFN Response to GL 87-05, Drywell Shell Thickness Monitoring for U1-3, Drywell Shell Evaluation, and evaluations for the Sand Bed Drains and Drain Lines.

The conclusions from the review noted that continued drywell shell Ultrasonic Testing in conjunction with updated Finite Element Analyses, statistical analyses, and subsequent calculations, shows a minimal corrosion rate and sufficient available margin for thinning at the SBR to support operation through the end of the subsequent period of extended operation. Furthermore, recent inspections of the BFN Unit 1 sand bed drains have shown the drains to be operational and functioning as designed, which allows the SBR to dry after being wetted, and in turn limits corrosion and wastage. However, in Unit 2, current walkdowns have found a lack of drainage from the Sand Bed Drains, which was verified from the initial GL 87-05 response as well as a composite Condition Report search. A Condition Report, in the Corrective Action Program was initiated to evaluate the drains for blockage and subsequently ensure the drains are open and functioning properly.

The BFN design incorporates a polyurethane foam and sand bed region in place of an air gap region and incorporates seal rupture drains to divert drywell bellows leakage. The design also incorporates a weir wall, which prevents drywell bellows leakage from entering the reactor well before being drained away with drains going to radwaste. Additionally, this prevents in-leakage to the sand pocket by use of a sheet metal cover, which is sealed to the drywell shell. The sealed cover prevents mortar from entering the sand pocket region. Located at the level of the sealed cover plate are sand filled drains that remove any in-leakage away from the sealed cover plate.

As part of the ASME Section XI, Subsection IWE program, several examinations and tests of components associated with the drywell sand bed and polyurethane foam region confirm that conditions that could lead to containment degradation would be identified and addressed before loss of an intended function. Inspections performed on October 17, 2022, confirmed that leaking is occurring at the Unit 1 drywell equipment hatch; however, evaluations have shown the results of that leaking have not put the involved SSCs in an unacceptable condition. The condition is still being monitored at the sand bed drain lines (via walkdowns, and tracking drops per minute), and in the case of components found with poor performance history, the Corrective Action Program will be used to support issue resolution.

The ASME Section XI Subsection IWE program, and 10 CFR 50 Appendix J program will be utilized to perform the inspections for these types of conditions as well as those pertaining to conditions of defects identified by moisture seal barrier inspections and coating inspections. However, this design, along with the aforementioned monitoring and testing measures, provide a substantial defense against water entering the drywell sand bed region. The ASME Section XI Subsection IWE program will ensure that degradation will be detected before a loss of function occurs. Furthermore, the ASME Section XI, Subsection IWE program has been enhanced to revise implementing procedures to carry forward Commitment No. NCO040006088, “Enhance ASME Section XI, Subsection IWE Program to perform a UT inspection of the sand bed area of the drywell liner of Units 1, 2, and 3.” Subsequent periodic inspections will be performed on each unit prior to entry into the subsequent period of extended operation and at least once every 10 years thereafter. The ultrasonic inspections of the Units 1, 2, and 3 drywell liner plate near the sand bed region will ensure the impacts from water intrusion, including potential degradation, on the outside surface of the drywell, are mitigated.

For BFN, no additional plant-specific activities are warranted beyond those described above, those pertaining to the Unit 2 drain lines, and those that are established as part of the ASME Section XI, Subsection IWE program. The continued monitoring of the containment shell in accordance with the ASME Section XI, Subsection IWE program (B.2.1.29), and the testing, conducted in accordance with the 10 CFR Part 50, Appendix J program (B.2.1.31), provide reasonable assurance that the loss of material due to corrosion of steel elements of the containment will be detected prior to a loss of intended function. These activities and programs provide assurance that the containment liner will remain capable of performing its design function through the subsequent period of extended operation.

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).*

   <u>Table 3.5.1 Item Number 3.5-1, 006:</u> This Item Number (3.5-1, 006) is applicable to BFN Mark I steel containments and evaluates loss of material due to general, pitting, and crevice corrosion in steel torus shell of the BFN Mark I containments exposed to air-indoor and treated water environments. The ASME Section XI, Subsection IWE program (B.2.1.29) and the 10 CFR Part 50, Appendix J program (B.2.1.31) will be used to manage the loss of material of steel elements in the torus shell. BFN procedures require wetted surface areas that are submerged to be visually examined.

   The areas containing the torus interior surfaces (waterline and below) are subjected to corrosion due to moisture and repeated wetting and drying in the waterline region. Accessible portions of the torus inside surface are inspected each refueling outage as required by BFN procedures. Additionally, underwater inspections are performed as part of the Protective Coating Monitoring and Maintenance program (B.2.1.35) on an interval not to exceed two years. Underwater coatings processes allow divers to inspect, document, and perform minor coatings repairs as one sequenced activity. These programs have been demonstrated to be effective in prevention of degradation to the torus surface.

   During BFN Unit 1 refueling outage U1R14 inspections in the torus immersion area, an indication of 134.3 mils metal loss was identified in Bay 13, plate 03 and has been reported on Notice of Indication (NOI) U1R14-006. A Condition Report was initiated to document the resulting engineering evaluation and follow up actions. The indication found in Bay 13 of the Unit 1 Torus was greater in depth than the acceptance criteria of 0.075". The conclusion from the resulting engineering evaluation (pertaining to the conditions identified by NOI U1R14-006) was that the indication identified was acceptable and in-line with all applicable code requirements. However, a visual examination (VT-1) of this indication was scheduled for Unit 1 refueling outage U1R17 in accordance with IWE-2420 of the 2013 Edition of ASME Section XI.

During BFN Unit 2 refueling outage U2R21 inspections in the torus immersion area, three indications ranging from 79.7 mils to 89.3 mils metal loss were identified in Bay-10 and have been reported on NOI U2R21-R007. NOI U2R21-R007 confirmed that at Bay 10, three areas of corrosion were indicated, there was isolated spot corrosion affecting the substrate, and metal loss was found to be > 75mils. The indications (noted to be on the weld seam) were found to have greater depth than the acceptance criteria of 0.075." Conservatively, the indication with the largest diameter indication combined with the deepest indication (0.5" diameter x 0.0893" deep) was evaluated to envelop all three indications. The evaluation concluded that all three indications (B10-P3-4, B10-P3-5, B10-P3-7) were acceptable and in-line with all applicable code requirements.

During BFN Unit 3 refueling outage U3R18, numerous pits greater than 0.035 inches were identified on submerged surfaces of Torus Bays 1 through 16 (per CR 1397211). Protective coating was re-applied to all pits greater than 0.030" in accordance with procedures.

Previous performances of BFN surveillance have documented evidence of minor coating degradation at the waterline region. This area appears to be within the category of “repeated loss of protective coatings;” however, based on above conclusions from operating experience (OE), it is determined that the underwater region of the torus has not been subjected to accelerated degradation.

Periodic inspections continue to be performed on the wetted surfaces in accordance with the ASME Section XI, Subsection IWE program (B.2.1.29) and follow-up inspections will be performed under the ASME Section XI, Subsection IWE program (B.2.1.29) in accordance with ASME Table IWE-2500-1, Examination Category E-C. Examinations conducted in accordance with ASME Section XI, Subsection IWE have not identified significant corrosion in the steel torus shell of the BFN Mark I containments.

3. *Loss 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).*

<u>Table 3.5.1 Item Number 3.5-1, 007:</u> This Item Number (3.5-1, 007) is applicable to the BFN Mark I steel containments and evaluates loss of material due to general, pitting, and crevice corrosion in steel torus ring girders and downcomers of the BFN Mark I containments exposed to air-indoor and treated water environments. ASME Section XI, Subsection IWE program (B.2.1.29) will be used to manage the loss of material of steel torus ring girders and downcomers.

Steel torus ring girders and downcomers of the BFN containments are subject to periodic examinations to detect loss of material due to general, pitting and crevice corrosion. The plant specific OE search revealed one Condition Report for Unit 3 associated with the torus ring girders and downcomers that identified loss of material due to pitting and crevice corrosion within an environment of air-indoor and treated water. The pitting and heavy corrosion on the downcomers was identified during an inspection and then entered into the Corrective Action Program. Previous OE from 1994, revealed Unit 1 Spent Fuel Pool leakage into the Unit 1 Reactor Building basement from the top of the downcomers onto the torus ring girders around Bay 14 for which the conditions (downcomers and ring girders noted to be corroding with iron oxide build up), have been documented in the Corrective Action Program, evaluated, and corrected as required. Any future deficiencies will be documented and addressed in accordance with Corrective Action Program.

The implementation of the ASME Section XI, Subsection IWE program (B.2.1.29) and the 10 CFR Part 50, Appendix J program (B.2.1.31) provides reasonable assurance that loss of material due to corrosion of the steel torus ring girders and downcomers will be adequately managed during the subsequent period of extended operation, such that the intended functions of the Mark I steel containment are maintained consistent with the current licensing basis.

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.

<u>Table 3.5.1 Item Number 3.5-1, 008:</u> This Item Number is not applicable to the BFN Mark I steel containments. The Item Number is applicable only to PWR prestressed concrete containments and BWR Mark II Concrete Containments.

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."*

<u>Table 3.5.1 Item Number 3.5-1, 009:</u> This item evaluates cumulative fatigue damage due to cyclic loading (only for existing analyses that are part of the current licensing basis (CLB)) in metal plates, suppression pool steel shells (including welded joints) and penetrations (including personnel airlock, equipment hatch, CRD hatch, penetration sleeves, dissimilar metal welds, and penetration bellows), vent header, vent line bellows, and downcomers of the BFN Mark I containments exposed to air-indoor and treated water environments. Components of the primary containment that were analyzed for fatigue and evaluated as a TLAA include the BFN torus, torus penetrations, vent header and downcomers, drywell to torus vents, safety relief valve discharge piping externally attached to the torus, other piping attached to the torus, and drywell to torus vent bellows. These components, in addition to the evaluation of fatigue as a TLAA for the containment process line penetration bellows, are addressed in Section 4.6. The containment analysis was completed in accordance with BFN design specifications.

Components of this Item Number 3.5-1, 009, for which fatigue analyses were not performed, include: the metal liner, airlock, equipment hatch, CRD hatch, and penetration sleeves. These components met the qualifications for fatigue waivers and will be addressed in Item Number 3.5-1, 027, which allows for the use of fatigue waiver in lieu of using supplemental surface examinations with ASME Section XI, Subsection IWE or crediting an appropriate 10 CFR Part 50, Appendix J, leak-rate test discussed in ASME Section XI, Subsection IWE. Fatigue analysis, or a fatigue waiver, for the drywell shell, drywell head, or drywell penetrations was not required since no cyclical loads were identified for these components in the applicable design specifications per the CLB. Though a fatigue analysis or waiver was not required, a fatigue exemption (waiver) analysis was performed. The conclusion of this analysis was that, in accordance with the rules of N-415.1 of Section III of the ASME Code, the drywell and the portions of its penetrations within the scope of the evaluation could be considered exempt from fatigue analysis.

The BFN Units 1 and 2 drywells were designed in accordance with the ASME Code Section III 1965 Edition with addenda through Winter 1966, and the Unit 3 drywell was designed in accordance with the ASME Code Section III 1965 Edition with addenda through Summer 1967. The criteria to be met for a fatigue waiver from these editions involves: 1) atmospheric to operating pressure cycles, 2) normal operation pressure fluctuations, 3) temperature differences between startup and shutdown, 4) temperature differences during normal operation, 5) temperature differences at dissimilar metal discontinuities, and 6) full range of stress due to mechanical loads.

Subsequent to the original design, design changes were made to some portions of the containment, which added new requirements for fatigue analyses, and are described below.

These changes include: (1) those to supports RS-3 and RS-8 (the attachment of 8-inch double extra strong portion to the ring girder clevis instead of the pipe clamp clevis from consideration of pool swell impact effects), (2) miter changes (where existing mitered joints in various torus internal piping were changed to standard welding elbow fittings in order to comply with piping code requirements), and (3) ECCS suction strainers.

The original design ECCS suction strainers were analyzed and modified for Long-Term Torus Integrity Program (LTTIP) loading conditions as described in section 8.5.2 of the Plant Unique Analysis Report (PUAR). Those strainers were subsequently replaced with much larger strainers in response to NRC Bulletin 96-03, as described in Sections C.3.5 and C.5.3 of the FSAR. Loading and acceptance criteria for the new strainers are described in Section C.5.3 of the FSAR.

Consequently, equipment attached to the torus containment structure, vent system, and within the boundary of influence of SRV discharge and LOCA hydrodynamic loads on torus attached piping must be qualified for LTTIP load combinations and allowable stresses. In the fatigue section of the PUAR, it was noted there were no abrupt changes in geometry. Despite that, a stress concentration factor of 1.5 was still conservatively assumed for the general torus stresses.

The load definitions used for the BFN plant unique analysis comply with the General Electric (GE) Mark I Containment Program - Load Definition Report, Revision 2 (NEDO- 21888 dated November 1981). The load definitions include assumed pressure and temperature transient cycles resulting from SRV discharge and design basis loss of coolant accident (LOCA) events. This report provided the methodology and definition of the thermal-hydraulic loads produced on the pressure suppression containment system of the GE Mark I containment during postulated loss-of-coolant accident, safety/relief valve discharges and related dynamic events. The PUAR describes that a fatigue evaluation of the torus attached piping (TAP), including the main steam SRV piping, was performed per a program developed by the Mark I Owner's Group. This analysis included the effects of mechanical load cycling in addition to the thermal expansion. The results justified fatigue life acceptability for TAP, including the SRV suppression chamber piping. These original analyses assume a limited number of main steam relief valve actuations throughout the 40-year life for the plant and are therefore TLAAs.

As such, only the components specified previously (primary containment structures, penetrations, and associated components) are evaluated for fatigue in Section 4.6 as they pertain to the BFN Mark I Steel Containment System primary containments. This does not include components related to the vessel internals (i.e., vessel shell) as they would be located inside of containment and are not evaluated as a part of containment fatigue.

Table 3.5.1 Item Number 3.5-1, 027: Fatigue analyses or fatigue waivers exist for all components in this Item Number pertaining to Mark I Steel Containments. The components with fatigue waivers include: the metal liner, airlock, equipment hatch, CRD hatch, and penetration sleeves. Components that do not have fatigue analyses have had fatigue waivers performed in lieu of managing for cracking due to cyclic loading with the 10 CFR Part 50, Appendix J program (B.2.1.31) and ASME Section XI, Subsection IWE program (B.2.1.29) via supplemental surface examinations or leak rate tests.

Table 3.5.1 Item Number 3.5-1, 040: This Item Number is not applicable to the BFN Mark I steel containments as it only applies to Mark II containments.

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.*

<u>Table 3.5.1 Item Number 3.5-1, 010 and Item Number 3.5-1, 039:</u> These items evaluate cracking due to SCC in stainless steel penetration sleeves, penetration bellows, vent line bellows, and dissimilar metal welds of the BFN Mark I steel containments exposed to the designated environment pertaining to each item. The enhanced ASME Section XI, Subsection IWE program (B.2.1.29) and the 10 CFR Part 50, Appendix J program (B.2.1.31) will be used to manage the cracking of stainless steel penetration sleeves, penetration bellows, vent line bellows, and dissimilar metal welds.

Material can potentially signify susceptibility of SSC. At BFN, the penetration sleeves, penetration bellows, and vent line bellows are stainless steel and susceptible to SCC; however, the suppression chamber shell at BFN is made of carbon steel and therefore is not susceptible to SCC.

Chemical factors should also be examined as stress corrosion cracking is associated with stress, temperature, and high concentration of chlorides/sulfates; however, while evidence of concentrations of chlorides and sulfate was found, there were no Condition Reports (CRs) or plant specific operating experience (OE) found for chloride or sulfate contaminants present at significant quantities inside the containment nor were there CRs or plant specific OE that pertained to areas of high stress or temperature associated with containment and SCC.

Section 5.2.3.2 of the FSAR specifies that thermal stresses in the steel shell due to temperature gradients were taken into account for the design (of the shell) and it is noted that the pipe penetrations are utilized as required by stress conditions. This further justifies mitigation of stress levels that could potential contribute to SCC.

Cyclical loading of stainless steel components, like those identified by this Item Number, is not expected to result in SCC at BFN because of the containment design which limits cyclical loadings. Furthermore, analysis of torus attached piping (TAP), which includes small bore piping (as defined as Class 1, 2-inch Nominal Pipe Size and smaller by FSAR C.3.2), was described in the Section 4.6 of this application and the PUAR. This analysis covered the effects of mechanical load cycling (in addition to thermal expansion) and resulted in the justification of fatigue life acceptability. Stress to the drywell components (thermal and mechanical) was determined to be limited, which also contributes to the mitigation of any potential stress corrosion cracking of the involved stainless-steel components. Consistent with the BFN design specifications, the containment was analyzed for fatigue. A fatigue waiver exemption calculation for the drywell penetrations was completed. BFN Units 1, 2 and 3 process lines that penetrate the drywell and experience significant differences in temperature during plant operation were designed with penetration bellows to ensure that fatigue due to thermal and mechanical loads during plant operation is acceptable (the design fatigue life of the bellows-type expansion joints for containment penetrations and vent pipes is 7000 cycles), which prevents a potential cause of SCC at the penetrations. The following process lines were designed with penetration bellows: the main steam lines, the feedwater lines, the HPCI steam line, the RHR supply and return lines, the RWCU pump suction line, and the core spray discharge lines. In addition, BFN has performed an assessment to evaluate containment and penetration fatigue, which reflected that criteria was met in regards to utilizing a fatigue waiver. License renewal applications for other Mark I containments designed to later code years have credited fatigue waivers. The criteria to be met for a fatigue waiver involves: 1) atmospheric to operating pressure cycles, 2) normal operation pressure fluctuations, 3) temperature differences between startup and shutdown, 4) temperature differences during normal operation, 5) temperature differences at dissimilar metals, and 6) mechanical loads. The primary containment fatigue assessment concluded that components from primary containment could be subject to cyclic loading; however, the thermal cycles can be extrapolated to less than 2200 for an 80-year plant life, which is roughly 31% of the 7000-cycle threshold design limit and signifies that the existing analysis is expected to remain valid for the 80-year plant life. The containment components with fatigue waivers include penetrations and dissimilar metal welds. The containment components with a fatigue analyses, that are addressed in Section 4.6 are representative of the stainless steel penetration bellows and vent line bellows and can be used as a leading indicator for these components.

Plant operating experience confirms that SCC of stainless steel penetration sleeves, penetration bellows, vent line bellows, and dissimilar metal welds of the BFN Mark I containments is not expected. Original design and installation specifications for containment penetration components such as bellows, welds, and penetration adapters required initial surface examinations to ensure no flaws existed as part of initial installation. Appropriate integrated and local leak rate testing is conducted for pressure boundary components per the 10 CFR Part 50, Appendix J program (B.2.1.31). For example, through-wall cracking would be detected by the Type B integrated leak rate test. Additionally, visual inspections (VT-1 and VT-3) are performed on accessible portions of the containment penetrations in accordance with the ASME Section XI, Subsection IWE program (B.2.1.29). BFN has not experienced a failure of the above listed containment components, as verified by a review of BFN operating experience. Additionally, the industry has found that the 10 CFR 50, Appendix J testing program has been effective in maintaining the pressure integrity of the primary containment boundaries. Furthermore, BFN has demonstrated good operating experience in maintaining the integrity of the primary containment boundaries. Moreover, the plant specific operating experience and Condition Report review did not identify failures at the BFN penetration bellows at BFN a result of routine testing by the BFN Appendix J program or inspections. Industry operating experience has also shown good performance of the primary containment components.

Even though the aging effect of SCC for stainless steel penetration sleeves, penetration bellows, vent line bellows, and dissimilar metal welds is not expected to occur, the testing, conducted in accordance with the 10 CFR Part 50, Appendix J program (B.2.1.31), and examinations, conducted in accordance with the ASME Section XI, Subsection IWE program (B.2.1.29), are applied to manage this aging effect and provide reasonable assurance that the cracking of stainless steel containment penetration bellows and dissimilar metal welds at containment penetration sleeves will be detected prior to a loss of intended function. To address concerns identified in this Further Evaluation, as well as Item Number 3.5-1, 027, the ASME Section XI, Subsection IWE program (B.2.1.29) will be enhanced to revise implementing procedures to state that for the containment components subject to cyclic loading, but with no CLB fatigue analysis, and pressurized during 10 CFR 50 Appendix J local leak rate testing, local leak rate testing will be performed and can be credited (if needed) in lieu of supplemental surface examinations. The majority of the surface of the stainless-steel penetration sleeves, penetration bellows, vent line bellows, and dissimilar metal welds are not accessible for visual inspection or surface examination for cracking due to the Mark I containment design; however, the design is such that the components like the penetration sleeves are accessible from the side.

Therefore, the 10 CFR Part 50, Appendix J program (B.2.1.31) and enhanced ASME Section XI, Subsection IWE program (B.2.1.29) will detect SCC for these stainless-steel components and dissimilar metal welds prior to a loss of intended function.

Table 3.5.1 Item Number 3.5-1, 038: This item is not applicable to the BFN Mark I steel containment. This Item is applicable instead to BWR Mark III concrete and steel containments.

3.5.2.2.1.7 Loss of Material (Scaling, Spalling) and Cracking Due to Freeze-Thaw

Loss of material (scaling, spalling) and cracking due to freeze-thaw could occur in inaccessible areas of PWR and BWR concrete containments. Further evaluation is recommended of this aging effect to determine the need for a plant-specific AMP or plant-specific enhancements to ASME Code Section XI, Subsection IWL, and/or Structures Monitoring AMPs, to manage these aging effects for plants located in moderate to severe weathering conditions. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Table 3.5.1 Item Number 3.5-1, 011: This item is not applicable to the BFN Mark I steel containments, which are supported on the Reactor Building foundation, for which the design incorporates concrete in the sub-foundation. The design originally was supported by a steel skirt, reinforced by filling the internal cavity of the skirt with concrete, and vibrated to fill all voids. This concrete provided vertical support to the steel containment, was completely enclosed by the skirt, and had no way to react with any environment. The skirt was later cut loose and the drywell now sits on a concrete pillar. The BFN Containment Structures are completely enclosed and sheltered within the air-indoor environment of the Reactor Building (secondary containment). As such, the containment structure concrete is not exposed to air-outdoor, or groundwater/soil environments. Thus, repeated freeze-thaw is not applicable, and Containment Structure concrete is not subject to loss of material (scaling, spalling) and cracking due to freeze-thaw. Therefore, no additional aging management or further evaluation of inaccessible concrete of the Containment Structure for this mechanism is 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 is required to manage this aging effect. Acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Table 3.5.1 Item Number 3.5-1, 012: This item is not applicable to the BFN Mark I steel containments, which were originally supported by the steel skirts, reinforced by filling the internal cavity of the skirts with concrete, and vibrated to fill all voids. This concrete provided vertical support to the steel containment, was completely enclosed by the skirt, and had no way to react with any environment or expand due to a reaction with the aggregates. The skirt was later cut loose and the drywell now sits on a concrete pillar. The Containment Structures are completely enclosed and sheltered within the air-indoor environment of the Reactor Building (secondary containment). Therefore, no additional aging management or further evaluation of inaccessible concrete of the Containment Structure for this mechanism is required.

3.5.2.2.1.9 Increase in Porosity and Permeability Due to Leaching of Calcium Hydroxide and Carbonation

Increase in porosity and permeability due to leaching of calcium hydroxide and carbonation could occur in inaccessible areas of concrete elements of PWR and BWR concrete and steel containments. Further evaluation is recommended to determine the need for a plant-specific AMP or plant-specific enhancements to ASME Code Section XI, Subsection IWL and/or Structures Monitoring AMPs, essential to manage these aging effects if leaching is observed in accessible areas that impact intended functions. Acceptance criteria are described in BTP RLSB 1 (Appendix A.1 of this SRP-SLR).

Table 3.5.1 Item Number 3.5-1, 014: This Item Number is not applicable to the BFN Mark I steel containments, which were originally supported by the steel skirts, reinforced by filling the internal cavity of the skirts with concrete, and vibrated to fill all voids. This concrete provided vertical support to the steel containment and was completely enclosed by the skirt. The skirt was later cut loose and the drywell now sits on a concrete pillar. The Item Number is applicable only to PWR concrete containments (Reinforced and Prestressed), PWR steel containments, BWR concrete containments (Mark I, II, and III), and BWR steel containments (Mark III). The Containment Structures for BFN are completely enclosed and sheltered within the air-indoor environment of the Reactor Building (secondary containment). The BFN Containment Structures are also not subject to a long-term flowing water environment, which would be conducive to porosity and permeability due to leaching of calcium hydroxide and carbonation. No increase in porosity and permeability has been identified in accessible areas of the Containment Structures that could have an impact on intended function. No additional aging management or further evaluation of inaccessible concrete of the Containment Structures for this aging mechanism is required.

3.5.2.2.2 Safety-Related and Other Structures and Component Supports

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 for 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 this SRP-SLR).*

   Table 3.5.1 Item Number 3.5-1, 042: This aging effect and mechanism, the loss of material (spalling, scaling) and cracking due to freeze-thaw, is applicable to BFN reinforced concrete structures. BFN is located in a region where weathering conditions are considered moderate as shown in Figure 1 of ASTM C33. The Structures Monitoring program (B.2.1.33) will be used to manage the loss of material (spalling, scaling) and cracking in both accessible and inaccessible areas of reinforced concrete for the Groups 2, 3, 8 and 9 structures. At BFN, there are no stand-alone Group 1 or 5 structures, which, at BFN, are part of the Group 2 Reactor Buildings. In addition, BFN does not have any stand-alone Group 7 structures. Furthermore, none of these structures are completely inaccessible, and there are significant portions of the structures that are accessible, which can provide indications of reinforced concrete conditions in inaccessible areas.

The original designs and construction of these structures conformed to ACI 318 (1963 and later revisions) and ACI 307 (1969) except as noted in licensing documents requiring higher design values/standards. Based on a sample of available concrete drawings for scoped in structures, the concrete mix design provides for low permeability by incorporating fly ash, water reducing agents, and adequate air entrainment (3 percent to 10 percent based on aggregate size and exposure) such that the concrete has good freeze-thaw resistance.

Structural reinforced concrete has not exhibited significant loss of material (spalling, scaling) and cracking due to freeze-thaw of in-scope reinforced concrete structures (based on documented site history). The same concrete specification was used for all structures at BFN, including the Groups 2, 3, 8, and 9 structures, such that these results are representative of the expected effects of spalling, scaling and cracking of all structures within the scope of subsequent license renewal. This operating experience provides objective evidence that the design and construction of external reinforced concrete at BFN has provided concrete with good freeze-thaw resistance. Although operating experience has not identified significant loss of material and cracking due to freeze-thaw, the Structures Monitoring program includes inspection for these aging effects in the accessible areas. As described in the current procedure for the inspection of existing structures, when buried reinforced concrete is exposed, by excavations, removal of equipment, or panels blocking access, it should be inspected and all defects identified and documented. While a review of operating experience and maintenance rule inspections found no documented cases of degradation for uncovered reinforced concrete, buried concrete is rarely exposed. Interviews with plant personnel indicate inspections of uncovered reinforced concrete have been performed, but these inspections have not been formally documented.

The visual inspections of reinforced concrete serve the purpose of identifying concrete damage in accordance with the requirements of the Structures Monitoring program. If unacceptable conditions due to freeze thaw are identified in the accessible areas of structures, the conditions are evaluated, and, depending upon the initial conditions and evaluation, corrective actions are developed that may include additional inspections to determine the extent of degraded conditions as part of the corrective action process. If freeze thaw damage were to occur, it would occur at the surface of concrete exposed to significant moisture levels and sudden drops in temperature to below freezing degrees. In general, these areas are exposed at the ground surface and are accessible for inspection. Because of the higher level of water exposure, the accessible BFN Group 6 structures may be used as a leading indicator for exposure to weathering conditions for the other reinforced concrete structures that are in-scope.

The condition of the accessible and above grade concrete is used as an indicator for the condition of the inaccessible and below grade structural components and provides reasonable assurance that degradation of inaccessible structural components will be detected before a loss of an intended function. The number of freeze-thaw cycles is expected to be greater for concrete above grade, and the potential moisture content in the concrete is expected to also be significant at the grade surface; therefore, inaccessible portions of the reinforced concrete structures are expected to be less susceptible to freeze-thaw damage than exposed areas of reinforced concrete structures. Freeze-thaw is not considered an aging mechanism for concrete components below the frost line (depth of 20 to 22 inches). The concrete associated with the electric cable tunnel (from Intake Pumping Station to powerhouse) is buried below the frost line and not subject to loss of material (spalling, scaling) and cracking due to freeze-thaw.

Since freeze-thaw damage proceeds at a comparatively slow rate, the required five-year inspection frequency and scope of Structures Monitoring program (B.2.1.33) are determined to be adequate, and no plant-specific AMP is required.

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 this SRP-SLR).*

   <u>Table 3.5.1 Item Number 3.5-1, 043:</u> This aging effect and mechanism, cracking due to expansion and reaction with aggregates, is considered applicable to BFN reinforced concrete structures. The Structures Monitoring program (B.2.1.33) will be used to manage cracking due to expansion and reaction with aggregates in both accessible and inaccessible areas of reinforced concrete for the Groups 2, 3, 4, 8, and 9 structures. At BFN, there are no standalone Group 1 or 5 structures, which, at BFN, are part of the Group 2 Reactor Buildings. In addition, BFN does not have any stand-alone Group 7 structures. Furthermore, none of these structures are completely inaccessible. There are significant portions of the structures that are accessible, which can provide indications of reinforced concrete conditions in inaccessible areas.

   The BFN structural concrete was constructed to preclude cracking due to this mechanism. The original designs and construction of these structures conformed to ACI 318 (1963 and later revisions) and ACI 307 except as noted in licensing documents requiring higher design values/standards. The aggregate in region of BFN is not known for reactive aggregate, including alkali reactive aggregate, and the site has very little possible evidence of aggregate alkali reactivity (only a few aggregate pop-outs have been observed). Despite this, the Structures Monitoring program (B.2.1.33) is conservatively being enhanced to include inspections of concrete areas for aging effects caused by reaction with aggregates.

   Based on a sample of available concrete drawings for scoped in structures, the concrete mix designs provide for low permeability by incorporating fly ash and water reducing agents. Concrete fine and coarse aggregates conform to ASTM C33. The cement is primarily Type II Portland cement with small scale concrete being Type I Portland cement. The Portland cement conforms to ASTM C-150.

   No significant cracking or swelling of concrete associated with expansion due to reaction with aggregates has been observed on BFN Group 2, 3, 4, 8, and 9 concrete structures during inspection or documented in Condition Reports resulting from plant work activities. Nevertheless, the Structures Monitoring program (B.2.1.33) continues to inspect and monitor reinforced concrete structures for cracking due to any mechanism. The condition of accessible and above grade concrete is used as an indicator for the condition of the inaccessible and below grade structural components and provides reasonable assurance that degradation of inaccessible structural components will be detected before a loss of an intended function. The same concrete specification was used for all structures at BFN, including the Groups 2, 3, 4, 8, and 9 structures, such that these results are representative of the expected effects of cracking due to expansion from reaction with aggregates of all structures within the scope of subsequent license renewal. If cracking due to expansion and reaction with aggregates was found to be significant, pattern cracking would be expected over most of the surfaces at grade level where the moisture level is higher. This has not been observed. The Group 6 structures (including the Intake Pumping Station and Gate Structures 2 and 3), have higher exposure to water compared to other reinforced concrete structures at BFN, and may be used as leading structures to indicate the presence of expansion and reaction with aggregates for the other reinforced concrete structures that are in-scope.

In addition, significant concrete deformations due to concrete expansion has not been detected at BFN. No significant concrete deformations due to differences in concrete expansion have been detected at the various accessible concrete structures that can be identified by looking for cracking between concrete elements below and above grade or at visible seismic gaps or expansion joints. This provides objective evidence that cracking associated with expansion due to reaction with aggregates has not yet occurred. Considering the age of BFN, the possibility of occurrence of expansion due to reactions with aggregates in the future is determined to be unlikely. Nevertheless, BFN will continue to look for indications of cracking associated with expansion due to reaction with aggregates.

As described in the current procedure for the inspection of existing structures, when buried reinforced concrete is exposed during excavations, it should be inspected and all defects identified and documented. Additionally, anytime concrete credited as inaccessible due to equipment, environmental conditions, or paneling becomes accessible, it should be inspected. While a review of operating experience and maintenance rule inspections found no documented cases of degradation of uncovered reinforced concrete, it should be noted that buried concrete is rarely exposed. Interviews with plant personnel indicate inspections of uncovered reinforced concrete have been performed, but these inspections have not been formally documented.

Since cracking due to expansion and reaction with aggregates occurs at a comparatively slow rate, the required five-year inspection frequency and scope of the Structures Monitoring program (B.2.1.33) are determined to be adequate, and no plant-specific AMP is required. However, the Structures Monitoring program (B.2.1.33) is being enhanced to include identification of leading indicator structures to receive an augmented inspection each cycle of the Structures Monitoring program. Augmented inspections will include examination for pattern cracking with darkened crack edges, water ingress, and misalignment inspections. These augmented inspection results will be evaluated by the responsible engineer each inspection cycle to identify changes that could be indicative of aging effects caused by reaction with aggregates. Such indications will be entered into the Corrective Action Program.

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.

<u>Table 3.5.1 Item Number 3.5-1, 044:</u> The Structures Monitoring program (B.2.1.33) will be used to manage cracks and distortion due to increased stress level from settlement for the Groups 3, 6, and 8 structures. At BFN, there are no stand-alone Group 1 or 5 structures, which at BFN, are part of the Group 2 Reactor Buildings. BFN does not have any Group 7 structures. Though this item was evaluated for all applicable groups (including Groups 2, 4, and 9), it was determined that, this aging mechanism is insignificant for the BFN concrete building structures that are founded on bedrock (such as the Reactor Building, Off Gas Treatment Building, Intake Pumping Station, and Reinforced Concrete Chimney). Furthermore, cracking and distortion due to settlement has not been identified in any BFN concrete building structures. Nevertheless, the Structures Monitoring program (B.2.1.33) continues to inspect and monitor applicable concrete structures for cracking due to any mechanism.

The foundations for the Turbine Buildings and Radwaste Building, among others, consist of steel piles that are founded on bedrock. Studies, such as those referenced in NUREG-1557 (Table B9), have shown that steel piles driven into undisturbed natural soil are not appreciably affected by corrosion due to the deficient oxygen environment that prevents significant loss of material. Piles driven into disturbed soil have been shown to experience only minor to moderate corrosion. In either case, the observed loss of material due to corrosion was not considered significant enough to impact the intended function of the piles, which is consistent with NUREG-1557. Therefore, cracking of the concrete due to settlement of the structure caused by corrosion of the piles is not expected.

Accessible piles are to be inspected as part of the 5-year maintenance rule inspections. Piles, exposed to environments such as air-outdoor, raw water, water-flowing, or water-standing, are to be monitored by either the Structures Monitoring program (B.2.1.33) or the Inspection of Water-Control Structures Associated with Nuclear Power Plants program (B.2.1.34).

The condition of the accessible and above grade concrete is used as an indicator for the condition of the inaccessible and below grade structural components and provides reasonable assurance that degradation of inaccessible structural components will be detected before a loss of an intended function. The same concrete specification was used for all structures at BFN, including the Groups 3, 6, and 8 structures, such that these results are representative of the expected effects of cracking and distortion due to increased stress levels from settlement of all structures within the scope of subsequent license renewal. Cracks extending into accessible areas, if any, will be managed by the Structures Monitoring program (B.2.1.33). If unacceptable conditions due to this mechanism were identified in the accessible areas of structures, procedures require that (1) extent of condition is determined and (2) that additional inspections or evaluations would address inaccessible and below grade portions of any affected structure. In addition, BFN examines exposed portions of the below-grade concrete when excavated for any reason, in accordance with the Structures Monitoring program

(B.2.1.33) and associated implementing procedures. Additionally, anytime inaccessible concrete (due to equipment, environmental conditions or paneling), becomes accessible, it should be inspected.

Table 3.5.1 Item Number 3.5-1, 046: This item is not applicable. The FSAR Chapter 12 and BFN Design Specifications do not have any reference to porous concrete. With the FSAR and specifications not providing for the use of porous concrete, it is concluded that there is no porous concrete utilized for the structural subfoundations. No further analysis is required for this item. BFN does not currently operate a dewatering program and dewatering is not credited for controlling settlement. Therefore, further considerations of the dewatering program are not required. The only recent recorded settlement was for the Electric Cable Tunnel running from the Intake Pumping Station to the Turbine Building. This settlement was evaluated and deemed to be acceptable. Since BFN dewatering system operation was terminated in 1983, no evidence of soil voids associated with the pumping has manifested. There is no further noted history of settlement since the dewatering system operation was terminated at BFN; however, this location within the cable tunnel will be specifically monitored for further settlement during the subsequent period of extended operation. Since the settlement proceeds at a comparatively slow rate, the required five-year inspection frequency and scope of the existing Structures Monitoring program (B.2.1.33) are determined to be adequate, and no plant-specific AMP is required. Inspection for loss of strength and settlement of concrete of the Electric Cable Tunnel between the Turbine Building and Intake Pumping Station is included in the scope of the existing Structures Monitoring program. Furthermore, an enhancement is being added to the Structures Monitoring program to revise implementing procedures to be consistent with ACI 349.3R-02 and SEI/ASCE 11-99 for selection of parameters to be monitored or inspected for concrete or steel structural elements and for steel liners, joints, coatings, and waterproofing membranes within the scope of the program.

4. *Increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide and carbonation could occur in below-grade inaccessible concrete areas of Groups 1-5 and 7-9 structures. Further evaluation is recommended 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 this SRP-SLR).*

Table 3.5.1 Item Number 3.5-1, 047: This aging effect and mechanism, increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation, is considered applicable to BFN reinforced concrete structures. The Structures Monitoring program (B.2.1.33) will be used to manage the increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation in both accessible and inaccessible areas for the Groups 2, 3, 8, and 9 structures. At BFN, there are no stand-alone Group 1 or 5 structures, which at BFN, are part of the Group 2 Reactor Buildings. In addition, BFN does not have any Group 7 structures. Similarly, though this item was evaluated for all applicable groups (including Group 4), it was determined that, this aging mechanism is not applicable to BFN Group 4 structures (which include the biological shield wall, RPV Pedestal, and RPV Support Skirt), as BFN has a Mark 1 steel containment (not a concrete containment). Furthermore, operating experience searches did not identify increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation associated with BFN Group 4 structures. Nevertheless, the Structures Monitoring program continues to inspect and monitor applicable concrete structures for cracking due to any mechanism. Notably, none of these structures are completely inaccessible, and there are significant portions of the structures that are accessible that provide indications of reinforced concrete conditions in inaccessible areas.

The same concrete specification was used for all structures at BFN, including the Groups 2, 3, 4, 8, and 9 structures, such that these results are representative of the expected effects of leaching and carbonation of all structures within the scope of subsequent license renewal. The BFN structural concrete was constructed to minimize these potential effects of leaching of calcium hydroxide and carbonation. The original designs and construction of these structures conformed to ACI 318 (1963 and later revisions) and ACI 307 except as noted in licensing documents requiring higher design values / standards. Based on a sample of available concrete drawings for scoped in structures, the concrete mix designs provide for low permeability by incorporating fly ash and water reducing agents. Concrete fine and coarse aggregates conform to ASTM C33. The cement is primarily Type II Portland cement with small scale concrete being Type I Portland cement. The Portland cement conforms to ASTM C-150.

As described in NUREG/CR-5466, Service Life of Concrete, section 5.2.3.3, the rate and extent of carbonation depends on the environmental relative humidity reaching a maximum at 50 percent relative humidity. Diffusion of gaseous carbon dioxide takes place several orders of magnitude more rapidly though air than through water. If concrete is saturated with water, the amount of carbonation occurring will be negligible. As a result, carbonation is more of a concern in air environments than in inaccessible soil or raw water environments. In addition, the carbonation rate of penetration slows over time. Therefore, accessible areas can be used as an indicator of reinforced concrete conditions in inaccessible areas for carbonation. The effects of carbonation have not been observed at BFN reinforced concrete structures. The same concrete specification was used for all structures at BFN, such that these results are representative of the expected effects of carbonation of all structures within the scope of subsequent license renewal. Leaching has been identified in the Torus rooms for Units 2 and 3 and loss of concrete due to spalling has been observed in the Turbine Building interior and in discrete areas of the Reactor Building subgrade structures (Note that in-leakage of water through expansion joints is not a defect in structural concrete as the strength of the concrete is not degraded by the failure of the expansion joint). The integrity of the concrete structures has not been impacted by the loss of concrete due to spalls, leaching of calcium hydroxide, or carbonation, further inspections have been conducted, and the concrete has been found to be sound. In addition, the available leaching results show that the iron in the test samples is small and the reinforcement is not being degraded due to the leaching. The leaching in these areas will continue to be observed as part of the Structures Monitoring program (B.2.1.33), which with the 5-year frequency is sufficient to manage the aging effect.

Groundwater considered aggressive due to low pH or high sulfates could potentially result in a chemical attack or leaching of the concrete (NUREG-1557, Table B3). Concrete degradation due to a chemical attack or leaching has not been observed at BFN. High calcium content has been identified in the Units 1 and 3 Station sumps (located in the Turbine Building), which is a potential indicator of leaching.

However, while the sump calcium levels were found to be higher than the average river and sample well calcium levels, they were within maximum values of both. Additionally, the sump calcium levels were below the average site soil calcium levels based on data included in the Subsurface Soil Corrosivity Assessment performed in 2023. As a result, the sump calcium levels are not considered elevated. Furthermore, inputs and flow paths to the Units 1 and 3 Turbine Building Station Sump Pumps were identified on BFN drawings, and the most vulnerable source areas were further identified, where excessive wear would be expected due to water flows (based on unfinished concrete surfaces, etc.). BFN Engineering personnel performed inspections of these areas, and no degradation consistent with leaching of calcium hydroxide or carbonation was identified. The inspection plan included the Unit 1 and 3 Station sumps (located in the Turbine Building), 3-inch track area gutter drains, auxiliary boiler trench, south fan room drains, and the north fan room drains. The trench from the Auxiliary Boilers has limited access and could not be inspected through the grating as there is expanded metal across the trench below the grating; however, water could be seen in the bottom of the trench. No excessive concrete wear indicative of leaching was identified in the remaining areas. This issue has been added to the Civil Design Structural Maintenance Rule Calculation and the existing Structures Monitoring aging management program. These areas are monitored on a five-year interval as part of routine maintenance rule inspections, and no increase in inspection frequency is required.

Test results for groundwater and raw water samples showed that at a limited number of locations (Monitoring Wells (MW): MW-10, MW-11, MW-13 and MW-17), the pH limits are below the lower threshold limit for pH of 5.5 per NUREG-1557, Table B3, and therefore qualify as aggressive. However, for all monitoring wells and raw water tests (e.g., river water), the identified sulfate and chloride levels are substantially lower than the threshold limit of 1500 ppm for sulfates and 500 ppm for chlorides per NUREG-1557, Table B3. This indicates a non-aggressive environment associated with those substances. Therefore, some of the inaccessible below grade reinforced concrete for Groups 2, 3, 4, 8, and 9 structures is potentially subject to an aggressive environment. However, the groundwater is only considered to be aggressive at some locations, and only for low pH levels. A further evaluation of the soil was performed, and the soil was not found to be aggressive; however, the following evaluation will conservatively evaluate any potential impacts on inaccessible concrete if the soil and groundwater are found to be aggressive. Low pH levels are a concern as a potential initiator of reinforcing steel corrosion, which could be initially detected as (1) cracking and spalling of concrete as well as (2) deterioration of the concrete. The groundwater at BFN was determined to generally not be aggressive with respect to sulfates or chlorides. Further evaluation of the localized low pH levels on BFN structures is performed below.

Operating experience at BFN, which looks for concrete deterioration due to any mechanism, has not identified porosity and permeability and loss of strength due to these mechanisms. When inaccessible reinforced concrete is exposed during excavations, removal of equipment, opening of locked hatches, removal of large panels, or removal of cladding, it should be inspected and all defects identified and documented per the existing Structures Monitoring program. No reports of defects have been documented from exposed inaccessible concrete (due to excavations or other activities), though buried concrete is rarely exposed. Interviews with plant personnel indicate inspections of uncovered reinforced concrete have been performed, but these inspections have not been formally documented. This operating experience provides further objective evidence that the concrete at BFN is not susceptible to an increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide, in addition to objective evidence that the inaccessible below grade reinforced concrete at BFN is not exhibiting reinforcing steel corrosion (which might have been expected considering the low pH levels found in a minority of the groundwater monitoring wells, as explained below).

The low pH levels are not found consistently across the site and were only found in a minority of the wells used for groundwater testing. Of these wells, only wells MW-10 and MW-11 are located near in-scope structures. Both of these monitoring wells are shallow wells, and the surrounding wells show acceptable pH levels. Additionally, from a subsequent soil test, the soil was found not to be aggressive. Therefore, it can be determined that low pH levels are localized, likely transitory, and not general to the site. MW-10 and MW-11 are located near the following Groups 2, 3, 4, 8, and 9 structures: Unit 3 Turbine Building, buried conduit banks and manways, Unit 3 Diesel Generator Building, Unit 3 Reactor Building, Cable tunnels between the Intake Pumping Station and Unit 3 Turbine Building, and Condensate Storage Supply Pipe Tunnel. The buried conduit banks and manways, and the Unit 3 Diesel Generator Building, are located above the water table and are not impacted by the low pH in the water table.

For the Turbine Building, most of the building is located above the water table. Additionally, the path of the groundwater is south-west from MW-10 parallel to face of the Turbine Building; thus, the Turbine Building is not impacted by low pH levels. The Cable Tunnel between the Turbine Building and Intake Pumping Station is located adjacent to MW-07, MW-08, and MW-08i, which show acceptable pH levels. Therefore, the tunnel is not subject to low pH levels. There have been no significant observations of cracks and leaching of the concrete in the Turbine Building or cable tunnel. Therefore, it can be reasoned that the localized low pH levels have not had negative impacts on these concrete structures.

The Reactor Building is nearer to MW-07, MW-08, MW-08i, and MW-09 than it is to MW-10 and MW-11. Therefore, with the adjacent monitoring wells having acceptable pH levels, it can be determined that the Reactor Building is not exposed to an aggressive environment.

The Structures Monitoring program (B.2.1.33) will continue to manage the increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation in both accessible and inaccessible areas of Groups 2, 3, 4, 8, and 9 structures. In addition, BFN will continue to examine exposed portions of the inaccessible concrete when exposed for any reason. Therefore, no additional measures for managing the aging effect of increase in porosity and permeability, and loss of strength for concrete, are required for inaccessible areas of Groups 2, 3, 4, 8, and 9 structures. Since leaching of calcium hydroxide and carbonation proceeds at a comparatively slow rate, the required five-year inspection frequency and scope of the Structures Monitoring program (B.2.1.33) are determined to be adequate, and no plant-specific AMP is required.

Further investigation of operating experience and documentation of the activities performed by BFN to monitor and mitigate the condition of leaching has been performed. The investigation revealed environments conducive to leaching exist at BFN as well as the condition of leaching; however, due to the minimal advancement and levels found and evaluated, the concrete was determined to retain its functional and operational integrity. Furthermore, the frequency of monitoring remains unchanged for all but the Gate Structures Numbers 2 and 3, whose frequencies do not pertain to leaching. The Structures Monitoring program (B.2.1.33) is determined to be adequate to manage the condition (no plant specific AMP is required). However, enhancements are being added to the Structures Monitoring program (B.2.1.33) to ensure adequate monitoring. The enhancements pertain to monitoring for aggressive environmental conditions with the inclusion of an additional implementing procedure as well as further instruction for Parameters Monitored or Inspected and Detection of Aging Effects to require indications of groundwater infiltration or through-concrete leakage will be assessed for aging effects.

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, “Code Requirements for Nuclear Safety-Related Concrete Structures,” specifies the concrete temperature limits for normal operation or any other long-term period. The temperatures shall not exceed 66 °C (150 °F) except for local areas, which are allowed to have increased temperatures not to exceed 93 °C (200°F). Further evaluation is recommended 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 °C (150°F) and local area temperature greater than 93 °C (200 °F)]. Higher temperatures may be allowed if tests and/or calculations are provided to evaluate the reduction in strength and modulus of elasticity and these reductions are applied to the design calculations. The acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

Table 3.5.1 Item Number 3.5-1, 048: This item is not applicable to BFN for either the components or situation (>150°F and >200°F for general area and localized temperatures, respectively). For example, the RHR System can be operated in parallel with the Spent Fuel Pool Cooling System (supplemental fuel pool cooling) to maintain the fuel pool temperature less than 150°F if a full core off load is performed.

Thermal insulation is also utilized at BFN to reduce thermal stresses. Reflective Metal Insulation (RMI) is managed using the One-Time Inspection program (B.2.1.20). Depending on the conditions found, the External Surfaces Monitoring of Mechanical Components program (B.2.1.23) will be used to identify and replace areas showing degradation. Other insulation (non RMI) is managed using the External Surfaces Monitoring of Mechanical Components program (B.2.1.23).

Additionally, review of the Equipment Qualification specification for electrical equipment revealed that general area, normal temperatures greater than 150 degrees Fahrenheit and local temperatures in excess of 200 degrees Fahrenheit are not applied at BFN. Plant operating experience has not identified elevated general area and local area temperature as a concern for concrete structural components. Hence, further evaluation of this item is not required.

3.5.2.2.2.3 Aging Management of Inaccessible Areas for Group 6 Structures

Further evaluation is recommended for inaccessible areas of certain Group 6 structure/aging effect combinations as identified below, whether or not they are covered by inspections in accordance with the GALL-SLR Report, AMP XI.S7, “Inspection of Water-Control Structures Associated with Nuclear Power Plants,” or Federal Energy Regulatory Commission (FERC)/US 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 for inaccessible areas for plants located in moderate to severe weathering conditions. Acceptance criteria are described in BTP RLSB-1 (Appendix A1 of this SRP-SLR).*

   Table 3.5.1 Item Number 3.5-1, 049: This aging effect and mechanism, loss of material (spalling, scaling) and cracking due to freeze thaw, is applicable to BFN reinforced concrete structures. BFN is located in a region where weathering conditions are considered moderate as shown in Figure 1 of ASTM C33. The Structures Monitoring program (B.2.1.33) will be used to manage the loss of material (spalling, scaling) and cracking in inaccessible areas of reinforced concrete for Group 6 structures. The Inspection of Water-Control Structures Associated with Nuclear Power program (B.2.1.34) will be used to manage the loss of material (spalling, scaling) and cracking for accessible Group 6 structures. The Condenser Circulating Water (CCW) conduits are included as part of the evaluation of Group 6 structures as their inspection will be added to the scope of the subsequent licensing renewal inspections. The CCW conduits are completely inaccessible during normal operations. Furthermore, the CCW conduits are constructed in accordance with the same specification and can be evaluated by comparison to the exposed concrete of other Group 6 structures. However, they are inspected from the inside during outages. The CCW conduits were investigated and found to be below the frost line, thus the aging effect of freeze-thaw was not considered applicable (negating its management with the Structures Monitoring program). The Group 6 structures have significant portions of the structures that are accessible and can provide indications of reinforced concrete conditions in inaccessible areas.

   The original designs and construction of these structures conformed to ACI 318 (1963 and later revisions) except as noted in licensing documents requiring higher design values / standards. Based on a sample of available concrete drawings for scoped in structures, the concrete mix design provides for low permeability by incorporating fly ash, water reducing agents, and adequate air entrainment (3 percent to 10 percent based on aggregate size and exposure) such that the concrete has good freeze-thaw resistance.

   Structural reinforced concrete has not exhibited significant loss of material (spalling, scaling) and cracking due to freeze-thaw in accessible areas of in-scope reinforced concrete structures. Gate Structures 2 and 3 have shown some signs of potential freeze thaw damage. Considering the age of the concrete, the high exposure to the elements, and close proximity to water at these locations, the level of cracking shown is within expectation and does not impact the intended function for Gate Structures 2 and 3. Additionally, cracking or spalling repairs are made, as appropriate, to (1) prevent cracks from propagating and (2) maintain the design function of the concrete. Inaccessible concrete is more protected from freeze-thaw cycles, and little to no freeze-thaw damage is expected; thus, the design function of the inaccessible concrete is also not expected to be adversely impacted. The operating experience provides objective evidence that the design and construction of external reinforced concrete at BFN has provided concrete with good freeze-thaw resistance. Although operating experience has not identified significant loss of material and cracking due to freeze-thaw, the Inspection of Water-Control Structures Associated with Nuclear Power Plants program (B.2.1.34) includes inspection for these aging effects in the accessible areas.

Though not part of the concrete structures, the sheet piling for the Gate Structures is also inspected as damage/degradation to the sheet piling due to freeze-thaw or other mechanisms could propagate into the concrete structures. The sheet piling for Gate Structures 2 and 3 was initially inspected annually; however, the inspection frequency was reduced to two years in 2014, and subsequently to three years in 2019. These changes were supported by review of previous inspection data which showed no significant decrease in the average pile thicknesses. Wear-rates and environmental conditions are not expected to change, and therefore there is no indication that significant degradation would occur within three-year intervals (such as thicknesses dropping below minimum acceptable values between inspections). A BFN calculation documents the thickness of the sheet piles remains within acceptable limits.

As described in the current procedure for the inspection of existing structures, when buried reinforced concrete is exposed during excavations, it should be inspected and all defects identified and documented. Additionally, anytime inaccessible concrete due to equipment, environmental conditions, or paneling becomes accessible, it should be inspected. While a review of operating experience and maintenance rule inspections found no documented cases of degradation of uncovered reinforced concrete, buried concrete is rarely exposed. Interviews with plant personnel indicated inspections of uncovered reinforced concrete have been performed, but these inspections have not been formally documented. The visual inspections of reinforced concrete identify concrete damage in accordance with the requirements of the Structures Monitoring program for inaccessible concrete, and the Inspection of Water-Control Structures Associated with Nuclear Power Plants program for accessible concrete. If unacceptable conditions due to freeze thaw are identified in the accessible areas of structures, the conditions are evaluated, and, depending upon the initial conditions and evaluation, corrective actions are developed, which may include additional inspections to determine the extent of degraded conditions as part of the corrective action process.

If freeze thaw damage was to occur, it would occur at the surface of concrete exposed to significant moisture levels and sudden drops in temperature (to below freezing). In general, these areas are exposed at the ground / water surface and are accessible for inspection. Because of the higher level of water exposure, the accessible portions of BFN Group 6 structures may be used as a leading indicator for exposure to weathering conditions for the other reinforced concrete structures that are in-scope for any structure group.

The condition of the accessible concrete is used as an indicator for the condition of the inaccessible and below grade / water structural components and provides reasonable assurance that degradation of inaccessible structural components will be detected before a loss of an intended function. The same concrete specification was used for all structures at BFN, including the Groups 6 structures, such that these results are representative of the expected effects of loss of material (spalling, scaling), and cracking due to freeze-thaw of all structures within the scope of subsequent license renewal.

The number of freeze-thaw cycles is expected to be greater for concrete at and above grade, and the potential moisture content in the concrete is expected to also be significant at the grade surface. Therefore, the inaccessible portions of the Group 6 structures are expected to be less susceptible to freeze-thaw damage than exposed areas of reinforced concrete structures.

Since freeze-thaw damage proceeds at a comparatively slow rate, the required five-year inspection frequency and scope of the Structures Monitoring program (B.2.1.33), supplemented by other inspection programs (Inspection of Water-Control Structures Associated with Nuclear Power Plants program (B.2.1.34)) and schedules, are determined to be adequate, and no plant-specific aging management program is 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 this SRP-SLR).*

<u>Table 3.5.1 Item Number 3.5-1, 050:</u> This aging effect and mechanism, cracking due to expansion and reaction with aggregates, is considered applicable to BFN reinforced concrete structures. The Structures Monitoring program (B.2.1.33) will be used to manage cracking due to expansion and reaction with aggregates in areas of reinforced concrete for Group 6 structures. This includes the concrete in inaccessible areas of Group 6 Structures. The Inspection of Water-Control Structures Associated with Nuclear Power Plants will be used to manage cracking due to expansion and reaction with aggregates in accessible areas of reinforced concrete for Group 6 structures. The Condenser Circulating Water (CCW) conduits are included as part of the evaluation of Group 6 structures as their inspection is being added to the scope of the subsequent licensing renewal inspections. The CCW conduits are completely inaccessible during normal operations. Furthermore, the CCW conduits are constructed in accordance with the same specification and can be evaluated by comparison with the exposed concrete of other Group 6 structures. However, the conduits are inspected from the inside during outages. The Group 6 structures have significant portions of the structures that are accessible that provide indications of reinforced concrete conditions in inaccessible areas.

The BFN structural concrete was constructed to preclude cracking due to this mechanism. The original designs and construction of these structures conformed to ACI 318 (1963 and later revisions) except as noted in licensing documents requiring higher design values / standards. The aggregate in the region of the BFN site is not known for reactive aggregate, including alkali reactive aggregate, and the site has very little evidence of possible aggregate reactivity (only a few aggregate pop-outs have been observed). Despite this, the Structures Monitoring program (B.2.1.33) and the Inspection of Water-Control Structures Associated with Nuclear Power Plants program (B.2.1.34) are being conservatively enhanced to include inspections of concrete areas for aging effects caused by reaction with aggregates.

Based on a sample of available concrete drawings for scoped in structures, the concrete mix designs provide for low permeability by incorporating fly ash and water reducing agents. Concrete fine and coarse aggregates conform to ASTM C33. The cement is primarily Type II Portland cement with small scale concrete being Type I Portland cement. The Portland cement conforms to ASTM C-150.

Cracking associated with expansion due to reaction with aggregates has not been observed on BFN Group 6 concrete structures, as described in operating experience. Nevertheless, the

Structures Monitoring program (B.2.1.33) and Inspection of Water-Control Structures Associated with Nuclear Power Plants program (B.2.1.34) will continue to inspect and monitor Group 6 concrete structures for cracking due to any mechanism. The condition of the accessible and above grade concrete is used as an indicator for the condition of the inaccessible and below grade / water structural components and provides reasonable assurance that degradation of inaccessible structural components will be detected before a loss of an intended function. The same concrete specification was used for all structures at BFN, including the Group 6 structures, such that these results are representative of the expected effects of cracking due to expansion from reaction with aggregates of all structures within the scope of subsequent license renewal. If cracking due to expansion and reaction with aggregates was determined to be significant, pattern cracking would be expected over most of the surfaces of the Group 6 structures continuously exposed to water. This has not occurred.

In addition, significant concrete deformation/loss of material due to concrete expansion has not been detected in Group 6 structures, which have comparatively high exposure to water compared to other reinforced concrete structures at BFN. The Group 6 structures may be used as leading structures to indicate the presence of expansion and reaction with aggregates for the other reinforced concrete structures that are not part of Group 6. Some indication of cracking potentially due to reactive aggregate was noted in the Intake Pumping Station suction well. However, this cracking was determined to not be adverse to the structural integrity of the concrete. No significant concrete deformation (that can be identified by looking for cracking between concrete elements below and above water due to differences in concrete expansion) has been detected for Group 6 structures. The guides for the trash rack screens on the Intake Pumping Station are embedded in the concrete both above and below the water line. During the recent replacement of those trash rack screens (which are located between opposing guides), no binding of the screens with the guides was observed, thereby demonstrating that there has not been any significant expansion of the concrete. This provides objective evidence that cracking associated with expansion due to reaction with aggregates has not yet occurred. Considering the age of BFN, the possibility of occurrence of expansion due to reaction with aggregates in the future is determined to be unlikely. Nevertheless, BFN will continue to look for indications of cracking associated with expansion due to reaction with aggregates.

As described in the current procedure for the inspection of existing structures, when buried reinforced concrete is exposed during excavations, it should be inspected and all defects identified and documented. Additionally, anytime inaccessible concrete due to equipment, environmental conditions, or paneling, becomes accessible, it should be inspected. While a review of operating experience and maintenance rule inspections found no documented cases of degradation of uncovered reinforced concrete, buried concrete is rarely exposed. Interviews with plant personnel indicated inspections of uncovered reinforced concrete have been performed, but these inspections have not been formally documented.

Since cracking due to expansion and reaction with aggregates proceeds at a comparatively slow rate, the required five-year inspection frequency and scope of the Structures Monitoring program (B.2.1.33), supplemented by other inspection programs (Inspection of Water-Control Structures Associated with Nuclear Power Plants program (B.2.1.34)) and schedules, are determined to be adequate, and no plant specific AMP is required. Note that the Structures Monitoring program and the Inspection of Water-Control Structures Associated with Nuclear

Power Plants program are being enhanced for identification of leading indicator structures to receive an augmented inspection each inspection cycle. Augmented inspections will include examination for pattern cracking with darkened crack edges, water ingress, and misalignment inspections. These augmented inspection results will be evaluated by the responsible engineer each inspection cycle to identify changes that could be indicative of aging effects caused by reaction with aggregates. Such indications will be entered into the Corrective Action Program.

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 if 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 this SRP-SLR).*

Table 3.5.1 Item Number 3.5-1, 051: This aging effect and mechanism, increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation, is considered applicable to BFN reinforced concrete structures. The Structures Monitoring program (B.2.1.33) will be used to manage the increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation in inaccessible areas of Group 6 structures. The Inspection of Water-Control Structures Associated with Nuclear Power Plants program (B.2.1.34) will be used to manage the increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation in accessible areas of Group 6 structures. The Condenser Circulating Water (CCW) conduits are included as part of the evaluation of Group 6 structures as their inspection will be added to the scope of the SLR inspections. Furthermore, the CCW conduits are completely inaccessible during normal operations, are constructed in accordance with the same specification, and can be evaluated by comparison to the exposed concrete of other Group 6 structures. However, they are inspected from the inside during outages. The Group 6 structures have significant portions of the structures that are accessible, which can provide indications of reinforced concrete conditions in inaccessible areas.

The same concrete specification was used for all structures at BFN, including the Group 6 structures, such that these results are representative of the expected effects of leaching and carbonation of all structures within the scope of subsequent license renewal. The BFN structural concrete was constructed to minimize these potential effects of leaching of calcium hydroxide and carbonation. The original designs and construction of these structures conformed to ACI 318 (1963 and later revisions) except as noted in licensing documents requiring higher design values / standards. Based on a sample of available concrete drawings for scoped in structures, the concrete mix designs provide for low permeability by incorporating fly ash and water reducing agents. Concrete fine and coarse aggregates conform to ASTM C33. The cement is primarily Type II Portland cement with small scale concrete being Type I Portland cement. The Portland cement conforms to ASTM C-150.

As described in NUREG/CR-5466, Service Life of Concrete, section 5.2.3.3, the rate and extent of carbonation depends on the environmental relative humidity reaching a maximum at 50 percent relative humidity. Diffusion of gaseous carbon dioxide takes place at a rate that is several orders of magnitude more rapidly through air than through water. If the concrete is saturated with water, the amount of carbonation occurring will be negligible. As a result, carbonation is more of a concern in air environments, than in inaccessible soil or raw water environments. In addition, the carbonation rate of penetration slows over time. Therefore, accessible areas can be used as an indicator of reinforced concrete conditions in inaccessible areas for carbonation. The effects of carbonation have not been observed at BFN reinforced concrete structures. The same concrete specification was used for all structures at BFN, such that these results are representative of the expected effects of carbonation of all structures within the scope of subsequent license renewal. Therefore, the effects of carbonation, such as an increase in porosity and permeability, are not expected to occur at the Group 6 structures of BFN.

Groundwater considered aggressive due to low pH or high sulfates could potentially result in chemical attack or leaching of the concrete (NUREG-1557, Table B3). Concrete degradation due to chemical attack or leaching has not been observed at BFN.

Test results for groundwater and raw water samples showed that at a limited number of locations (Monitoring Wells (MW): MW-10, MW-11, MW-13 and MW-17s), the pH limits are below the lower threshold limit for pH of 5.5 per NUREG-1557, Table B3, and therefore qualifies as aggressive. However, for all monitoring wells and raw water tests (e.g., river water), the identified sulfate and chloride levels are substantially lower than the threshold limit of 1500 ppm for sulfates and 500 ppm for chlorides per NUREG-1557, Table B3. This indicates a non-aggressive environment associated with those substances. Therefore, some of the inaccessible below grade reinforced concrete for Group 6 structures is subject to an aggressive environment. However, only the groundwater is considered to be aggressive and only for low pH levels. This is a conservative approach because a further evaluation of the soil was performed, and the soil was found to be non-aggressive. Low pH levels are a concern as a potential initiator of reinforcing steel corrosion (which could be initially detected as cracking and spalling of concrete) as well as deterioration of the concrete. The groundwater at BFN is determined to generally not be aggressive with respect to sulfates or chlorides. Further evaluation of the localized low pH levels on BFN structures is performed below.

Operating experience at BFN, which looks for concrete deterioration due to any mechanism, has not identified an increase in porosity and permeability and loss of strength due to these mechanisms. When inaccessible reinforced concrete is exposed during excavations, removal of equipment, opening locked hatches, removal of large panels, or removal of cladding, it should be inspected and all defects identified and documented per the existing Structures Monitoring program (though buried concrete is rarely exposed). Interviews with plant personnel indicated inspections of uncovered reinforced concrete have been performed, but these inspections have not been formally documented. No reports of defects have been documented for accessible areas of Group 6 structures or from excavations around inaccessible concrete; however, this operating experience also provides objective evidence that (1) the concrete at BFN is not susceptible to an increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and (2) that the inaccessible below grade reinforced concrete at BFN is not exhibiting reinforcing steel corrosion, which might have been expected considering the low pH levels found in a minority of the groundwater monitoring wells, as explained below.

The low pH levels are not found consistently across the site and were only found in a minority of the wells used for groundwater testing. Of these wells, only wells MW-10 and MW-11 are located near the following Group 6 structures: Intake Pumping Station and CCW Conduits. Both of these monitoring wells are shallow wells and the surrounding wells show acceptable pH levels. Additionally, from a subsequent soil test, the soil was found to be non-aggressive. Therefore, it can be determined that low pH levels are localized, likely transitory, and not general to the site. The Intake Pumping Station is located downstream of MW-11, given a South West groundwater flow. MW-07 and MW 19 are located in the South West direction from MW-11, and would be considered downstream of the groundwater flow. MW-07 and MW-19 are physically much closer to the Intake Pumping Station. Based on the above, MW-07 and MW-19 are considered a much better determination of the groundwater chemistry at the Intake Pumping Station. The groundwater at MW-07 and MW-19 is not aggressive; therefore, the Intake Pumping Station is determined to not be exposed to an aggressive environment. Additionally, much of the Intake Pumping Station structure is exposed to the river water which is non-aggressive. Furthermore, there has been no significant observations of cracks and leaching of the concrete and it can be reasoned that the localized low pH levels have not had negative impacts on the concrete structure.

The CCW conduits cannot be inspected from the exterior. The CCW intake conduits and discharge conduits are completely buried. However, the CCW conduits have been regularly inspected from their interiors during outages and no evidence has been found of concrete degradation. The CCW conduits are filled with water taken from the forebay which is non-aggressive. With no signs of concrete degradation, and the non-aggressive river water in the CCW conduits, the regular inspections will be sufficient to identify defects before they become critical.

The Structures Monitoring program (B.2.1.33) will continue to manage the increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation in inaccessible areas of Group 6 structures. The Inspection of Water-Control Structures Associated with Nuclear Power Plants program (B.2.1.34) will continue to manage these aging effects for the accessible areas of Group 6 structures. In addition, BFN will continue to examine exposed portions of the inaccessible concrete when excavated for any reason. Therefore, no additional measures for managing the aging effect of increase in porosity and permeability; loss of strength for concrete are required for inaccessible areas of Group 6 structures. Since the increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation proceeds at a comparatively slow rate, the required five-year inspection frequency and scope of the Structures Monitoring program (B.2.1.33), supplemented by any other inspection programs (Inspection of Water-Control Structures Associated with Nuclear Power Plants program (B.2.1.34)) and schedules, are determined to be adequate, and no plant specific aging management program is required.

Further investigation of OE and documentation of activities at BFN to monitor and mitigate the condition of leaching has been performed. The investigation revealed environments conducive to leaching exist at BFN as well as the condition of leaching; however, due to the minimal advancement and levels found and evaluated, the concrete was determined to retain its functional and operational integrity. The Structures Monitoring program (B.2.1.33), supplemented by other programs (Inspection of Water-Control Structures Associated with Nuclear Power Plants program (B.2.1.34)) and schedules, is determined to be adequate to manage the condition (no plant specific AMP is required). However, enhancements are being added to the Structures Monitoring program (B.2.1.33) to ensure adequate monitoring. The enhancements pertain to monitoring for aggressive environmental conditions with the inclusion of an additional implementing requirements for Parameters Monitored or Inspected and Detection of Aging Effects to require indications of groundwater infiltration or through-concrete leakage will be assessed for aging effects. These enhancements are consistent with guidance provided in NUREG-2191 AMP XI.S6, Structures Monitoring.

3.5.2.2.2.4 Cracking Due to Stress Corrosion Cracking, and Loss of Material Due to Pitting and Crevice Corrosion

Cracking due to SSC and loss of material due to pitting and crevice corrosion could occur in (a) Group 7 and 8 SS tank liners exposed to standing water; and (b) SS and aluminum alloy support members; welds; bolted connections; or support anchorage to building structure exposed to air or condensation (see SRP-SLR Sections 3.2.2.2.2, 3.2.2.2.4, 3.2.2.2.8, and 3.2.2.2.10 for background information).

For Group 7 and 8 SS tank liners exposed to standing water, further evaluation is recommended of plant-specific programs to manage these aging effects. The acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP-SLR).

For SS and aluminum alloy support members; welds; bolted connections; support anchorage to building structure exposed to air or condensation, the plant-specific OE and condition of the SS and aluminum alloy components are evaluated to determine if the plant-specific air or condensation environments are aggressive enough to result in loss of material or cracking after prolonged exposure. The aging effects of loss of material and cracking in SS and aluminum alloy components is not applicable and does not require management if (a) the plant-specific OE does not reveal a history of pitting or crevice corrosion or cracking and (b) a one-time inspection demonstrates that the aging effects are not occurring or that an aging effect is occurring so slowly that it will not affect the intended function of the components during the subsequent period of extended operation. The applicant documents the results of the plant-specific OE review in the SLRA. Visual inspections conducted in accordance with GALL-SLR Report AMP XI.M32, "One-Time Inspection," are an acceptable method to demonstrate that the aging effects are not occurring at a rate that affects the intended function of the components. One-time inspections are conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32. If loss of material or cracking has occurred and is sufficient to potentially affect the intended function of SS or aluminum alloy support members; welds; bolted connections; or support anchorage to building structure, either: (a) enhancing the applicable AMP (i.e., GALL-SLR Report AMP XI.S3, "ASME Section XI, Subsection IWF," or AMP XI.S6, "Structures Monitoring"); (b) conducting a representative sample inspection consistent with GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components;" or (c) developing a plant-specific AMP are acceptable programs to manage loss of material or cracking (as applicable). Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combinations which are not susceptible to SCC when used in structural support applications include 1xxx series, 3xxx series, 6061-T6x, and 5454-x. For these alloys and tempers, the susceptibility of cracking due to SCC is not applicable. If these alloys or tempers have been used, the SLRA states the specific alloy or temper used for the applicable in-scope components.

<u>Table 3.5.1 Item Number 3.5-1, 052:</u> This Item Number is not applicable to BFN. Group 7 is not credited for BFN; however, three components/areas were screened in for Group 8: Condensate Water Storage Tank Foundations and trenches, Nitrogen Storage Tank Foundation, and CAD System Storage Tank Foundation. These were evaluated, and it was determined that BFN does

not have Group 7 and 8 stainless steel tank liners exposed to standing water, necessitating no further evaluation.

Table 3.5.1 Item Number 3.5-1, 099: This Item Number evaluates aluminum and stainless steel support members, welds, bolted connections, and support anchorage to the structures that are classified as Class 1, 2, 3, or MC and are exposed to an environment of air or condensation. Once component applicability was established, the components were analyzed for the loss of material due to pitting and crevice corrosion and/or cracking due to SSC. It was found that the One-Time Inspection program (B.2.1.20) will be used to manage cracking and loss of material of the stainless steel and aluminum components in the Containment Structure and Component Supports commodity group. A plant-specific OE review was performed, which did not reveal a history of pitting or crevice corrosion or cracking of aluminum or stainless steel support members or connections.

Visual inspections, conducted per the One-Time Inspection program (B.2.1.20), will be performed to confirm that loss of material due to pitting and crevice corrosion or cracking due to SCC are not occurring at a rate that affects the intended function of the components. The one-time inspections will be conducted between the 50th and 60th year of operation. If loss of material or cracking is identified during the one-time inspections 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, the condition will be entered into the corrective action program. Depending upon the conditions found, corrective actions will include the actions such as the following: (a) enhancing the ASME Section XI, Subsection IWE program (B.2.1.29) and ASME Section XI, Subsection IWF program (B.2.1.30); (b) determining the extent of condition by conducting a representative sample inspection consistent with the External Surfaces Monitoring of Mechanical Components program (B.2.1.23); or (c) developing a plant-specific AMP to manage loss of material or cracking (as applicable).

Table 3.5.1 Item Number 3.5-1, 100: This Item Number covers the aluminum and stainless steel support members, welds, bolted connections, and support anchorage to building structure that are exposed to an environment of air and condensation and subject to the loss of material due to pitting and crevice corrosion and cracking due to SCC.

These structures and component supports come from the Reactor Buildings, Primary Containment Structures, Radwaste Building, Conduit and Conduit Supports, Electrical Panels, Racks, Cabinets, and Other Enclosures, Hazard Barriers and Elastomers, HVAC Duct Supports, Miscellaneous Steel, Penetrations and Sleeves, Pipe Whip Restraints, Piping Supports, Thermal Insulation, Tube Track, and Other Miscellaneous Structures. With the exception of aluminum alloy thermal insulation jacketing, specific aluminum alloys were typically not specified during original construction; therefore, the potential aging effects were considered for all aluminum components aligned to this Item Number. Aluminum alloy thermal insulation jacketing is constructed of alloy 3003.

A plant-specific OE review was performed and did not reveal a history of pitting or crevice corrosion or cracking of aluminum or stainless steel components or connections.

The One-Time Inspection program (B.2.1.20) will be used to manage cracking and loss of material of the stainless steel and aluminum components exposed to air environments. This program will be used to manage the loss of material of cranes, hoists, and their associated structural bolting. The materials include aluminum and steel as well as references to the Fuel Handling and Storage System.

Cracking has not been identified as an aging effect at BFN for stainless steel and aluminum components or connections exposed to air environments or that with condensation. However, visual inspections will be conducted accordingly, per the One-Time Inspection program (B.2.1.20) to confirm that loss of material due to pitting and crevice corrosion or cracking due to SCC is not occurring at a rate that affects the intended function of the structural components. The one-time inspections will be conducted between the 50th and 60th year of operation.

In accordance with BFN One-Time Inspection program (B.2.1.20), if the engineering evaluation of inspection results concludes that age-related degradation is occurring and could result in the loss of component function during the subsequent period of extended operation, the unaccepted condition is documented in the corrective action program. Depending upon the conditions found, corrective actions will include the actions such as the following: (a) enhancing the Structures Monitoring program (B.2.1.33); (b) determining the extent of condition by conducting a representative sample inspection consistent with the External Surfaces Monitoring of Mechanical Components program (B.2.1.23); or (c) developing a plant-specific AMP to manage loss of material or cracking (as applicable).

3.5.2.2.2.5 Cumulative Fatigue Damage

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.

Table 3.5.1 Item Number 3.5-1, 053: The components listed for this Item Number are not applicable to BFN. The BFN current licensing basis contains no fatigue analysis for Groups B1.1, B1.2, and B1.3 component supports, which are screened under the Component Support group. A CLB fatigue analysis does not exist for support members, bolted connections, or supported anchorages to building structures. These components are not subject to fatigue, cyclical loading, or cyclical displacement. Therefore, a TLAA is not required to be evaluated in accordance with 10 CFR 54.21(c) for these components.

However, a CLB fatigue analysis was identified as a TLAA for the refueling bellows containment skirt (also referred to as the refuel containment skirt). The summary of this analysis is provided in Section 4.3, with a projected 80-year Cumulative Usage Factor (CUF) within the applicable acceptance criteria (CUF limit of 1.0 for ASME Section III locations). Refer to Section 4.3 for additional details.

3.5.2.2.2.6 Reduction of Strength and Mechanical Properties of Concrete Due to Irradiation

Reduction of strength, loss of mechanical properties, and cracking due to irradiation could occur in PWR and BWR Group 4 concrete structures that are exposed to high levels of neutron and gamma radiation. These structures include the reactor (primary/biological) shield wall, the *sacrificial shield wall, and the reactor vessel support/pedestal structure. Data related to the effects and significance of neutron and gamma radiation on concrete mechanical and physical properties is limited, especially for conditions (dose, temperature, etc.) representative of light-water reactor (LWR) plants. However, based on literature review of existing research, radiation fluence limits of 1 × 10^{19} neutrons/cm^2 neutron radiation and 1 × 10^8 Gy (1 × 10^{10} rad) gamma dose are considered conservative radiation exposure levels beyond which concrete material properties may begin to degrade markedly (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).

Table 3.5.1 Item Number 3.5-1, 097: The potential for reduction of strength, loss of mechanical properties, and cracking of reinforced concrete due to irradiation primarily concerns the reactor vessel shield wall, also called the sacrificial shield wall or the containment biological shield (CBS), which is located around the reactor vessel in the drywell. The CBS is described in the BFN FSAR Section 12.2.2.6. The reactor vessel is supported from the bottom on a skirt on the reactor vessel support/pedestal structure, as described in FSAR Section 12.2.2.3.3, where the radiation exposure is much lower than at the CBS along the reactor vessel belt line. The reactor vessel support/pedestal structure is a reinforced concrete hollow cylinder supporting both the reactor vessel and the CBS. The bottom and top portions of the shield wall are comprised of standard density concrete with limestone aggregate. The central portion of the CBS is comprised of high-density concrete with hematite aggregate.

The estimated (calculated) fluence levels or irradiation dose received by any portion of the concrete from neutron (E > 0.1 MeV) or gamma radiation does not exceed the respective threshold level limits of 1E+19 neutrons/cm^2 neutron radiation or 1E+10 rad gamma dose during the subsequent period of extended operation; additionally, there was no plant-specific operating experience identified that reflects irradiation damage that could impact the intended function of the CBS. Therefore, a plant-specific program to manage aging effects of irradiation is not required and the Structures Monitoring program (B.2.1.33) will be used to manage the potential for reduction of strength, loss of mechanical properties, and cracking due to irradiation of reinforced concrete near reactor vessel (CBS).

SLRA Table 4.2.1.1-4 shows a maximum fluence level of 1.69E+18 neutrons/cm^2 neutron radiation (E > 1 MeV) at the inner diameter of the reactor vessel at the belt line for the 64 Effective Full Power Years (EFPY) projected for the period of subsequent period of extended operation. The maximum estimated fluence levels at the concrete are based on determining the attenuation by the intervening reactor vessel shell and air gap and determining the neutron fluence levels at the energy levels of interest regarding potential concrete damage. The following is based on EPRI Report 3002018400, Revision 1, September 2020, “Basis for Evaluation of Concrete Biological Shield Wall for Aging Management.”

- The following equation represents neutron attenuation through the thickness of the reactor vessel:

  $f_{1T} = f_{0T}e^{-0.33x}$ neutrons/cm^2 neutron radiation (E > 1.0 MeV)

  Where:

  f_{1T} = neutron fluence (neutrons/cm^2) at the outside surface of the reactor vessel (1T)

  f_{0T} = neutron fluence at the inner surface of the reactor vessel (0T) = 1.69E+18 neutrons/cm^2

  x = thickness of the reactor vessel = 6.125 inches

  This yields a 1T fluence value of 2.24E+17 neutrons/cm^2.

- The radiation exposure at the outside of the reactor vessel for neutrons with a fluence cutoff energy E > 0.1 MeV is estimated to be a factor of less than seven times the fluence value of 2.24E+17 neutrons/cm^2 for neutrons with a fluence cutoff energy E > 1 MeV. The following equation represents the conversion of 1T fluence for neutron energy greater than 1.0 MeV to 1T fluence for neutron energy greater than 0.1 MeV:

  $f_{0.1MeV} = 2.123 \times e^{0.191x} \times f_{1.0\ MeV}$

  Where:

  $f_{0.1\ MeV}$ = neutron fluence (neutrons/cm^2) at the outside surface of the reactor vessel (1T) (E > 0.1 MeV)

  $f_{1.0\ MeV}$ = neutron fluence (neutrons/cm^2) at the outside surface of the reactor vessel (1T) (E > 1.0 MeV)

  x = thickness of the reactor vessel (inches)

  This results in a 1T reactor vessel fluence value of 1.53E+18 neutrons/cm^2 (E > 0.1 MeV).

- The neutron exposure at the concrete of the reactor vessel shield wall is attenuated by the air gap between the reactor vessel and the reactor vessel shield wall and is conservatively reduced by 10 percent (EPRI Report 3002018400). This ignores the mirror insulation in the applicable areas as well as any neutron attenuation it may provide. As a result, the neutron exposure at the inside surface of the CBS, conservatively ignoring the steel on the inside of the shield wall, is equal to 0.9 x 1.53E+18 neutrons/cm^2 = 1.38E+18 neutrons/cm^2 neutron radiation (fluence cutoff energy E > 0.1 MeV). This value is less than the recommended radiation fluence limit of 1E+19 neutrons/cm^2 neutron radiation.

A plant specific calculation was performed to determine the gamma dose rates in the CBS concrete. The evaluation is based on the methodology presented in EPRI Report 3002018400. A method to determine a plant specific gamma dose value is presented on Page 2-14. The equation to calculate the ratio of the gamma dose rate (mRad/s) to neutron fluence (neutrons/cm^{2}s) at the biological shield inner surface is:

$R_A = (5.6585E - 06)(DWN / x) - 1.2950E - 05$

Where:

R_A = ratio of the gamma dose rate (mRad/s) to neutron flux (neutrons/cm^{2}s) at the biological shield inner surface = 7.14E-06

DWN = downcomer thickness = 21.75 in

x = reactor pressure vessel thickness = 6.125 in

Then, the gamma dose at the CBS wall at the end of the evaluation period can be calculated as:

$\gamma_{CBS} = R_A \times \Phi_{0.1\ MeV\ (CBS)} \times 0.001$ (mrad / rad)

Where:

γ_{CBS} = the estimated gamma dose at the CBS, rad

$\Phi_{0.1\ MeV\ (CBS)}$ = Neutron fluence at the CBS wall surface (E > 0.1 MeV) = 1.38E+18 neutrons/cm^2

Note: The neutron fluence input value is already corrected for the plant end of life condition (80 years, 64.0 EFPY). Therefore, no correction concerning the plant capacity factor is required.

The above calculation results in a calculated gamma dose value of 9.85E+09 rad at the CBS inner surface for BFN. Further, this conservatively ignores the shielding, which would be provided by the CBS carbon steel liner on the inside surface, as well as the vessel mirror insulation, and any other obstructions in between. This is less than the acceptance criteria of 1E+10 rad.

The methodology within EPRI Report 3002018400 is based upon equations developed within EPRI Report 3002016055, “Long-Term Operations: Estimation of Gamma Dose in Boiling Water Reactor Concrete Biological Shield Walls.” EPRI Report 3002016055 demonstrates that for the evaluated BWRs (except for GE BWR-2 designs), the methodologies for calculating neutron fluences and gamma doses in the CBS overpredicts computational benchmarks by 28-62% and 23-151%, respectively.

Recent research on the gamma dose limit of 1E+10 rad reveals that this value may be overly conservative after subsequent reviews of previous test data. A paper published by I. Maruyama et al, Journal of Advanced Concrete Technology, Volume 15, 440-523 (2017), funded by the Japanese Regulator, concluded that there is no direct effect of gamma dose on concrete strength and recommends removing gamma dose limits. This paper also concludes that previous studies that showed a decrease in concrete strength as a function of gamma dose were seeing an elevated temperature effect due to the high gamma flux in accelerated aging tests. Similar issues with the gamma dose limit of 1E+10 rad were also identified in NUREG/CR-7171, November 2013, “A Review of the Effects of Radiation on Microstructure and Properties of Concrete Used in Nuclear Power Plants.”

<u>SLR Reactor Vessel Support Steel Evaluations</u>

In addition to the potential aging effects due to irradiation of reinforced concrete, a loss (or reduction) in fracture toughness due to irradiation embrittlement of the reactor vessel (RV) support steel is a potential aging effect considered in this subsection. NUREG-1509, May 1996, “Radiation Effects on Pressure Vessel Supports,” is a resource for addressing the issue for subsequent license renewal. Accordingly, a further evaluation of the RV supports for radiation induced embrittlement is provided below.

The reactor vessel is shown In FSAR Figure 4.2-1. The RV support structures at BFN are described in FSAR Section 4.2.4. The RV support structures consist of a cylindrical skirt attached to the bottom head of the reactor vessel and a lateral stabilizer at the top of the reactor vessel shield wall.

SLRA Figures 4.2.1-1, 4.2.1-2, and 4.2.1-3 show the elevations of the reactor vessel belt line components. The radiation fields are significantly reduced above and below this region considering distance correction factors using the inverse square law as described in EPRI Report 3002008128, July 2016, “Structural Disposition of Neutron Radiation Exposure in BWR Vessel Support Pedestal.” The RV support skirt knuckle region is fabricated from ASME SA-302, Grade B. FSAR Section 4.2.4.1 notes that the as-fabricated initial Nil-Ductility Transition Temperature (NDTT) for all carbon and low-alloy steel used in the main closure flanges, closure bolting material, and the shell and head materials connecting to these flanges, including the connecting circumferential weld material, is limited to a maximum of 10°F as determined by ASTM E208. The support skirt is fabricated from two shell courses, the uppermost being made of SA 516 Gr. 70 carbon steel, and the lower being ASTM A36 structural steel. FSAR Section 4.2.4.1 notes that for the vessel support skirt material, the initial NDTT is no higher than 56°F for Unit 1, and 40°F for Units 2 and 3. NUREG-1509, Section 4.2.1 notes that radiation embrittlement is not an issue for RV support skirts.

EPRI Report 3002020999, January 2022, “Aging Management of Reactor Vessel (RV) Supports for Extended Operation,” has recently been prepared to address irradiation of the RV support and applies to BFN. Section 2 of the report shows the BWR vessel support designs for which the report is addressing. The EPRI report evaluates the estimated maximum fluence levels and degree of embrittlement that were projected for the high stress (knuckle) region of the BWR reactor vessel supports. Also, the temperatures and loading conditions in the knuckle region were examined to determine whether irradiation induced embrittlement of the reactor vessel support steel could reduce the level of toughness and affect the margins against brittle fracture. The EPRI Report specifies that due to the proximity of the knuckle region to the Reactor Coolant System (RCS) inventory, the estimated temperature of the knuckle region is approximately that of the RCS. Therefore, an estimated NDTT for 80-year plant life can be calculated using Regulatory Guide 1.99, Revision 2. Reviewing the NRC Reactor Vessel Integrity Database (RVID), Revision 2, SA-302 Grade B materials used in reactor vessels have approximate average copper and nickel abundances of 0.16 wt. percent and 0.47 wt. percent, respectively. This combination would yield a chemistry factor of 108 °F from RG 1.99, Revision 2, a ΔNDTT of 12°F, and an 80-year NDTT of 22°F. This calculation still provides a sufficient margin of plus 78°F to the lowest service temperature (LST) of 100°F.

Concerning the supports and support skirt, EPRI Report 3002020999 states that the maximum total fluence in this region is not expected to exceed 1E+17 neutrons/cm^{2}s (E > 1.0 MeV) or 2.02E-04 dpa for 80-years of plant operation. From Figure 3-1 of NUREG-1509, this dpa level correlates to a ΔNDTT of about 22°F. The initial NDTT for ASTM A36 is estimated to be 39°F per Table 4-1 of NUREG-1509. This would be an 80-year NDTT of 61°F for the supports. With a LST for the supports of 100°F, the margin between the 80-year NDTT and the LST is 39°F. For the support skirt, considering initial NDTT of 56°F for Unit 1, and 40°F for Units 2 and 3, the calculated 80-year NDTT is 78°F for Unit 1 and 62°F for Units 2 and 3. For the support skirt, this provides margin of 22°F for Unit 1 and 38°F for Unit 2 and 3. Therefore, the integrity of the reactor vessel supports is assured, and no additional aging management of reactor vessel supports beyond the current ASME Section XI, Subsection IWF program (B.2.1.30) is necessary for aging effects due to irradiation during the subsequent period of extended operation of BFN.

Accordingly, there is reasonable assurance that a loss (or reduction) of fracture toughness due to irradiation embrittlement will not affect the ability of the RV support steel to perform its intended functions through the subsequent period of extended operation.

SLR Sacrificial Shield Wall Structural Steel Evaluation

In addition to the potential aging effects due to irradiation of reinforced concrete, a loss (or reduction) in fracture toughness due to irradiation embrittlement of the nearby structural steel is a potential aging effect considered in this subsection. Specifically, the potential effects of irradiation on the steel elements of the CBS are addressed below in this further evaluation. The potential effects of irradiation on the concrete elements of the CBS and the reactor vessel supports are addressed in the previous subsections of this further evaluation.

As described in FSAR, Section 12.2.2.6, the CBS is a 27-inch-thick cylindrical structure that consists of twelve steel columns equally spaced and tied together by a 1/4-inch-thick steel liner plates. Ring girders and transfer beams connect the columns together. Concrete was placed between the columns to provide radiation shielding. The CBS has an inside diameter of approximately 24-feet and is approximately 49-feet high. For the seismic design, the CBS was modeled as a vertical beam anchored at the bottom to the top of the reactor pedestal with a lateral stabilizer at the top of the CBS. The lateral stabilizer consists of circular truss, which transfers loads through additional attachments to the reactor vessel, the top of the CBS, the interior and exterior of the drywell, and the interior of the shield wall outside of the drywell. The lateral stabilizer function is to transfer lateral forces applied at the top of the reactor vessel and the top of the CBS, through the drywell shell to the concrete shield wall outside of the drywell.

NUREG-1509 is a resource for addressing the potential effects of irradiation on the steel elements of the CBS for SLR. Accordingly, a further evaluation of the CBS for radiation induced embrittlement is provided below. Per NUREG-1509, the reduction in fracture toughness assessment of the CBS steel can be based on a transition temperature analysis, wherein a demonstration is made that there is adequate margin between the normal operating temperature and the ductile-to-brittle fracture mode transition temperature (commonly known as the NDTT for end-of-life (EOL) conditions. The transition temperature approach is based on the proposition that catastrophic failure by brittle fracture can be avoided by maintaining the normal operating CBS service temperature above the NDTT of the steel. When using the transition temperature to evaluate the CBS integrity, the NDTT at EOL should include the irradiation induced shift.

As described in the original construction specifications and confirmed in the material receipt records, the steel elements of the CBS, consisting of the columns, 1/4-inch-thick steel liner plates, ring girders, and transfer beams, are fabricated from steel conforming to ASTM A36 low carbon steel. The assumed initial NDTT plus 1.3σ, provided in NUREG-1509 Table 4-1 and Table 4-2 for this material is 39°F. The original specification did not specify that any additional copper or nickel be incorporated into the ASTM A36 material and there are no chemical measurements for copper or nickel in material receipt records for the BFN shield walls made from ASTM A36 low carbon steel. The assumed chemical composition for the A36 steel shield wall (from NUREG/CR-6399, April 1977, "Results of Charpy V-Notch Impact Testing of Structural Steel Specimens Irradiated at ~30°C to 1 x 10^{16} neutrons/cm^2 in a Commercial Reactor Cavity," Table 2) is Cu = 0.05 weight %, Ni = 0.07 weight %, trace elements for A36 material. These are typical measured values from plate materials taken from the Trojan reactor and these chemistry values are representative of other shield wall plates.

NUREG-1509 provides a method for approximating the NDTT shift by determining exposure in terms of displacements per atom (dpa), and then using Figure 3-1 of that reference to establish the irradiation induced shift of the NDTT. By fitting the experimental data in NUREG-1509, a trend curve prediction model was developed for embrittlement shift versus displacements per atom (dpa) that incorporated the effects of flux and fluence, irradiation temperature, and gamma heating for application to the vessel supports as shown by the upper bound line in Figure 3-1 in NUREG-1509. That model included an upper bound transition temperature shift that was adjusted with zero-degree shift at a dpa of 10^{-5}. For the purpose of this evaluation of the CBS, the use of the NUREG-1509 trend curve model for NDTT shift versus dpa is very conservative since there is very little copper in the ASTM A36 materials and because the ratio of low energy neutrons to fast neutrons in the CBS is much smaller than that used in the test reactor experiments.

Fluence calculations were performed to confirm the attenuation effects through the RV internals, the RV and outward to the CBS. The peak fluence at the shield wall inner surface for Unit 3 64 EFPY (80-years) equates to a displacement per atom = 6.15E-04 dpa. It is noted that Unit 3 provides the most bounding DPA value for use in the sacrificial steel evaluation.

The prediction of the potential irradiation induced NDTT shift using the NUREG-1509 method shown in Figure 3-1 is described below. The potential irradiation induced NDTT is a function of the dpa fluence as shown in Figure 3-1 of NUREG-1509. The dashed upper bound curve is based on the fit to the experimental test data for reactor vessel carbon steel support materials (which did not include ASTM A36 materials) under low temperature, low flux neutron exposure conditions. For the CBS with a peak inner diameter surface fluence equating to 6.15E-04 dpa, the corresponding NDTT shift is 56°F. Therefore, the total adjusted NDTT = Initial NDTT + potential irradiation induced NDTT shift = 39°F + 56°F = 95°F. This is well below the normal operating temperature (average, Mode 1) in the drywell of 136°F.

Welding of the CBS was performed in accordance with the original design specification and the construction records that required the use of the shielded metal arc welding process utilizing E-7018 electrodes, which conformed to specification ASME SFA-5.1-1971 through Summer 1973 Addenda and do not incorporate a copper covering on the electrode. The original specification did not specifically add requirements for any additional copper or nickel and there are no chemical measurements for copper or nickel in material receipt records for the weld rods used for the BFN CBSs beyond the standard material requirements, which do not include requirements for copper or nickel. As a result, the weld materials are similar to the ASTM A36 materials for the purpose of this further evaluation, and the same conclusions are made regarding the potential effects of irradiation induced embrittlement for the weld materials incorporated into the CBS as were made regarding the CBS steel elements.

Therefore, an evaluation of the potential effects of irradiation on the steel elements of the CBS was performed for BFN, using the projected fluence values for 64 Effective Full Power Years (EFPY) and an adjusted NDTT for the steel materials using the methodology in NUREG-1509. The evaluation demonstrates that there is adequate margin between the normal operating temperature and the ductile-to-brittle fracture mode transition temperature that was adjusted for the potential effects due to irradiation. The evaluation concludes that the potential effects of irradiation on the steel elements of the CBS materials, including the welding material, are not significant. As a result, the integrity of the CBS is assured, and no additional aging management of the CBS beyond the current Structures Monitoring program is necessary for aging effects due to irradiation during the subsequent period of extended operation of BFN.

Accordingly, there is reasonable assurance that a loss (or reduction) of fracture toughness due to irradiation embrittlement will not affect the ability of the CBS support steel to perform its component intended functions through the subsequent period of extended operation. Since the radiation dose to the CBS bounds other Class 1 steel structures at BFN, and the aging effects due to irradiation are not significant for the CBS, a plant specific aging management program is not necessary to manage the aging effects due to irradiation of structural steel components.

<u>Conclusions</u>

The integrity of the reactor vessel supports is assured, and no additional aging management of reactor vessel supports beyond the ASME Section XI, Subsection IWF program (B.2.1.30) is necessary for aging effects due to irradiation during the subsequent period of extended operation of BFN.

The integrity of the CBS is assured, and no additional aging management of the CBS beyond the Structures Monitoring program (B.2.1.33) is necessary for aging effects due to irradiation during the subsequent period of extended operation of BFN.

3.5.2.2.3 Quality Assurance for Aging Management of Nonsafety-Related Components

QA provisions applicable to Subsequent License Renewal are discussed in Appendix A, Section A.1.4, and Appendix B, Section B.1.3.

3.5.2.2.4 Ongoing Review of Operating Experience

Ongoing review of operating experience is addressed in Appendix A, Section A.1.5, and Appendix B, Section B.1.4.

3.5.2.3 Time-Limited Aging Analysis

The time-limited aging analyses identified below are associated with the Containments, Structures and Component Supports:

- Section 4.6, Primary Containment Fatigue Analyses
- Section 4.7, Other Plant-Specific Analyses
  - Section 4.7.2, Radiation Degradation of Drywell Expansion Gap Foam

3.5.3 Conclusion

The Containments, Structures and Component Supports that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the Containments, Structures and Component Supports are identified in the summaries in Section 3.5.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the subsequent period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the Containments, Structures and Component Supports components will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the current licensing basis during the subsequent period of extended operation.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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	Not Applicable. This Item Number is not applicable to the BFN Mark I steel containment. See Subsection 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	Not Applicable. This Item Number is not applicable to the BFN Mark I steel containment. See Subsection 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	Not Applicable. This Item Number is not applicable to the BFN Mark I steel containment. See Subsection 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	Not Applicable. This Item Number is not applicable to the BFN Mark I steel containment. See Subsection 3.5.2.2.1.3.1.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 005	Steel elements (inaccessible areas): liner; liner anchors; integral attachments, steel elements (inaccessible areas): suppression chamber; drywell; drywell head; embedded shell; region shielded by diaphragm floor (as applicable)	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, “ASME Section XI, Subsection IWE,” and AMP XI.S4, “10 CFR Part 50, Appendix J”	Yes	Not Applicable. This Item Number is not applicable to the BFN Mark I steel containment. See Subsection 3.5.2.2.1.3.1.
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	Consistent with NUREG 2191. The 10 CFR Part 50, Appendix J program (B.2.1.31) and ASME Section XI Subsection IWE program (B.2.1.29) will be used to manage loss of material of the steel elements: torus shell exposed to air - indoor uncontrolled or treated water in the BFN Mark I Steel Containment Structure. See Subsection 3.5.2.2.1.3.2.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG 2191. The ASME Section XI, Subsection IWE program (B.2.1.29) will be used to manage loss of material of the steel elements in the downcomers and torus shell ring girders exposed to air - indoor uncontrolled or treated water in the BFN Mark I steel Containment Structure. See Subsection 3.5.2.2.1.3.3.
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	Not Applicable. This Item Number is not applicable to the BFN Mark I steel containment. See Subsection 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	Fatigue is a TLAA; further evaluation is documented in Subsection 3.5.2.2.1.5.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 010	Penetration sleeves; penetration bellows	Cracking due to SCC	AMP XI.S1, “ASME Section XI, Subsection IWE,” and AMP XI.S4, “10 CFR Part 50, Appendix J”	Yes	Consistent with NUREG 2191. The 10 CFR Part 50, Appendix J program (B.2.1.31) program and ASME Section XI, Subsection IWE program (B.2.1.29) will be used to manage cracking of stainless steel and dissimilar metal welds of penetration sleeves and penetration bellows exposed to an air - indoor uncontrolled in the BFN Mark I Steel Containment Structure. See Subsection 3.5.2.2.1.6.
3.5-1, 011	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses	Loss of material (spalling, scaling) andcracking 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	Not Applicable. This Item Number is not applicable to the BFN Mark I steel containment.
3.5-1, 012	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, containment,concrete fill-in annulus	Cracking due toexpansion 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	Yes	Not Applicable. This Item Number is not applicable to the BFN Mark I steel containment.
3.5-1, 013	This Item Number is not listed in NUREG-2191 Vol 1 and was deleted from NUREG-2192.				
3.5-1, 014	Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, containment	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Plant-specific aging management program or AMP XI.S2, “ASME Section XI, Subsection IWL,” and/or AMP XI.S6, “Structures Monitoring,” enhanced as necessary	Yes	Not Applicable. This Item Number is not applicable to the BFN Mark I steel containment. See Subsection 3.5.2.2.1.9.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 015	This Item Number is not listed in NUREG-2191 Vol 1 and was deleted from NUREG-2192.				
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	Not Applicable. This Item Number is not applicable to the BFN Mark I steel containment.
3.5-1, 017	This Item Number is not listed in NUREG-2191 Vol 1 and was deleted from NUREG-2192.				
3.5-1, 018	Concrete (accessible areas): dome; wall; basemat; ring girders;buttresses	Loss of material (spalling, scaling) andcracking due to freeze-thaw	AMP XI.S2, “ASME Section XI, Subsection IWL,” and/or AMP XI.S6,“Structures Monitoring”	No	Not Applicable. This Item Number is not applicable to the BFN Mark I steel containment.
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	Not Applicable. This Item Number is not applicable to the BFN Mark I steel containment.
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	Not Applicable. This Item Number is not applicable to the BFN Mark I steel containment.
3.5-1, 021	Concrete (accessible areas): dome; wall; basemat; ring girders;buttresses; reinforcingsteel	Cracking; loss of bond; and loss ofmaterial (spalling,scaling) due to corrosion of embedded steel	AMP XI.S2, “ASME Section XI, Subsection IWL,” and/or AMP XI.S6, “Structures Monitoring”	No	Not Applicable. This Item Number is not applicable to the BFN Mark I steel containment.
3.5-1, 022	This Item Number is not listed in NUREG-2191 Vol 1 and was deleted from NUREG-2192.				

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Not Applicable. This Item Number is not applicable to the BFN Mark I steel containment.
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 chemicalattack	AMP XI.S2, “ASME Section XI, Subsection IWL,” and/or AMP XI.S6, “Structures Monitoring”	No	Not Applicable. This Item Number is not applicable to the BFN Mark I steel containment.
3.5-1, 025	This Item Number is not listed in NUREG-2191 Vol 1 and was deleted from NUREG-2192.				
3.5-1, 026	Moisture barriers (caulking, flashing, andother 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. The ASME Section XI, Subsection IWE program (B.2.1.29) will be used to manage loss of sealing of the elastomer seals, gaskets, and moisture barriers exposed to air - indoor uncontrolled in the Hazard Barriers and Elastomers Structural Commodities Group.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG 2191. For the stated containment pressure-retaining components subjected to cyclic loading for which no CLB fatigue analysis exists for the time of the SLRA submittal (metal liner, metal plate, airlock, equipment hatch, CRD hatch, and penetration sleeves), a plant-specific further evaluation was performed to demonstrate that cracking due to cyclic loading is an aging effect that does not require aging management for the components. The option to perform a fatigue waiver was used in lieu of managing for cracking due to cyclic loading with the 10 CFR Part 50, Appendix J program (B.2.1.31) and ASME Section XI, Subsection IWE program (B.2.1.29) via supplemental surface examinations or leak rate test. See Subsection 3.5.2.2.1.5.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.5-1, 028	Personnel airlock, equipment hatch, CRDhatch	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, "ASME Section XI, Subsection IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	No	Consistent with NUREG 2191. The 10 CFR Part 50, Appendix J program (B.2.1.31) and ASME Section XI, Subsection IWE program (B.2.1.29) will be used to manage loss of material of the personnel airlock, CRD hatch, and equipment hatch, in the containment structure exposed to air - indoor uncontrolled.
3.5-1, 029	Personnel airlock, equipment hatch, CRD hatch: locks, hinges, and closure mechanisms	Loss of leak tightnessdue to mechanical wear	AMP XI.S1, "ASME Section XI, Subsection IWE," and AMP XI.S4, "10 CFR Part 50, Appendix J"	No	Consistent with NUREG 2191. The 10 CFR Part 50, Appendix J program (B.2.1.31) and ASME Section XI, Subsection IWE program (B.2.1.29) will be used to manage loss of leak tightness due to mechanical wear in the personal airlock, CRD hatch, and equipment hatch locks, hinges, and closure mechanisms located in the containment structure exposed to air - indoor uncontrolled.
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. The 10 CFR Part 50, Appendix J program (B.2.1.31) and ASME Section XI, Subsection IWE program (B.2.1.29) will be used to manage loss of preload for pressure-retaining bolting in the containment structure.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
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. The ASME Section XI, Subsection IWE program (B.2.1.29) will be used to manage loss of material for pressure retaining bolting in the containment exposed to air-indoor uncontrolled.
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. This Item Number is not applicable to the BFN Mark I steel containment.
3.5-1, 033	Seals and gaskets	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	AMP XI.S4, “10 CFR Part 50, Appendix J”	No	Consistent with NUREG-2191. The 10 CFR Part 50, Appendix J program (B.2.1.31) will be used to manage loss of sealing of the elastomer seals, gaskets,and moisture barriers exposed to air - indoor uncontrolled in the Hazard Barriers and Elastomers Structural Commodities Group.
3.5-1, 034	Service Level I coatings	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting,or physical damage	AMP XI.S8, “Protective Coating Monitoring and Maintenance”	No	Consistent with NUREG-2191. The Protective Coating Monitoring and Maintenance program (B.2.1.35) will be used to manage loss of coating or lining integrity of the Service Level I coatings exposed to air - indoor uncontrolled or treated water in the Containment Structure.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 035	Steel elements (accessible areas): liner; liner anchors; integral attachments, penetration sleeves, drywell shell; drywell head; drywell shell in sand pocket regions; suppression chamber; drywell; embedded shell; region shielded by diaphragm floor (as applicable)	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, “ASME Section XI, Subsection IWE,” and AMP XI.S4, “10 CFR Part 50, Appendix J”	Yes	Consistent with NUREG 2191. The 10 CFR Part 50, Appendix J program (B.2.1.31) and ASME Section XI,Subsection IWE program (B.2.1.29) will be used to manage loss of material of the Steel elements in accessible areas of the drywell shell, drywell head, and drywell shell in sand pocket regions in addition to penetration sleeves exposed to air - indoor uncontrolled or treated water, in the Mark I Steel Containment Structure. See Subsection 3.5.2.2.1.3.1.
3.5-1, 036	Steel elements: drywellhead; downcomers	Loss of material due to mechanical wear,including fretting	AMP XI.S1, “ASME Section XI, Subsection IWE”	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWE program (B.2.1.29) will be used to manage loss of material for the steel elements of the drywell head and downcomers exposed to air – indoor uncontrolled in the Containment Structure.
3.5-1, 037	Steel elements: suppression chamber(torus) liner (interior surface)	Loss of material due to general (steel only), pitting, crevicecorrosion	AMP XI.S1, “ASME Section XI, Subsection IWE,” and AMP XI.S4, “10 CFR Part 50, Appendix J”	No	Not Applicable. This Item Number is not applicable to the BFN Mark I steel containment.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 038	Steel elements: suppression chambershell (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	Not Applicable. This Item Number is not applicable to the BFN Mark I steel containment. See Subsection 3.5.2.2.1.6.
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	Consistent with NUREG 2191. The 10 CFR Part 50, Appendix J program (B.2.1.31) and ASME Section XI, Subsection IWE program (B.2.1.29) will be used to manage cracking of the vent line bellows exposed to air – indoor uncontrolled in the Mark I Steel Containment Structure. This item was also used as a basis for the refueling bellows assemblies in the primary containment structures. See Subsection 3.5.2.2.1.6.
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	Not Applicable. This Item Number is not applicable to the BFN Mark I steel containment. See Subsection 3.5.2.2.1.5.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 041	Steel elements: drywell support skirt, steel elements (inaccessibleareas): support skirt	None	None	No	Consistent with NUREG-2191. This Item Number has been used for steel components in the Containment Structure (drywell shell and drywell support skirt). Steel components contained within concrete do not require an aging management program as described in the GALL-SLR report.
3.5-1, 042	Groups 1-3, 5, 7-9: concrete (inaccessibleareas): foundation	Loss of material (spalling, scaling) andcracking due to freeze-thaw	Plant-specific aging management program or AMP XI.S6, “Structures Monitoring,” enhanced as necessary	Yes	Consistent with NUREG 2191. The Structures Monitoring program (B.2.1.33) will be used to manage loss of material (spalling, scaling) and cracking due to freeze-thaw that could occur in below grade inaccessible areas of reinforced concrete structures exposed to an air – outdoor or groundwater/ soil environment in Group 2, 3, 8, and 9 structures. See Subsection 3.5.2.2.2.1.1.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 043	All Groups except Group 6: concrete (inaccessible areas): all	Cracking due toexpansion from reaction with aggregates	Plant-specific aging management program or AMP XI.S6, “Structures Monitoring,” enhanced as necessary	Yes	Consistent with NUREG 2191. The Structures Monitoring program (B.2.1.33) will be used to manage the loss of material (spalling, scaling) and cracking in inaccessible areas of reinforced concrete for the Groups 2, 3, 8 and 9 structures. This Item Number is used for reinforced concrete exposed to air - indoor uncontrolled, air - outdoor, groundwater/soil, soil, or water-flowing in all structures except for Group 6 structures. Group 6 structures are addressed under Item Number 3.5.1-050. See Subsection 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	Consistent with NUREG-2191. The Structures Monitoring program (B.2.1.33) will be used to manage cracks and distortion due to increased stress level from settlement for structures founded on soil. Cracks, distortion, increase in component stress level due to settlement are not aging effects requiring management for structures founded on rock or bearing piles. See Subsection 3.5.2.2.2.1.3.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 045	This Item Number is not listed in NUREG-2191 Vol 1 and was deleted from NUREG-2192.				
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	Not applicable. BFN does not contain porous concrete. However, the aging effect pertaining to settlement and foundations / subfoundations was captured via Item Number 3.5-1, 044. See Subsection 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	Consistent with NUREG 2191. This aging effect and mechanism, increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation, is considered applicable to BFN reinforced concrete structures. The Structures Monitoring program (B.2.1.33) will be used to manage the increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide and carbonation in inaccessible areas for the Groups 2, 3, 4, 8, and 9 structures. See Subsection 3.5.2.2.2.1.4.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 048	Groups 1-5: concrete: all	Reduction of strength and modulus due to elevated temperature (>150°F general; >200°F local)	Plant-specific aging management program or AMP XI.S6, “Structures Monitoring,” enhanced as necessary	Yes	Not Applicable. There are no concrete structures exposed to elevated temperature (>150°F general; >200°F local) pertaining to this Item Number for the BFN. See Subsection 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) andcracking due to freeze-thaw	Plant-specific aging management program or AMP XI.S6, “Structures Monitoring,” enhanced as necessary	Yes	Consistent with NUREG 2191. The Structures Monitoring program (B.2.1.33) will be used to manage the loss of material (spalling, scaling) and cracking in both accessible and inaccessible areas of reinforced concrete for Group 6 structures (except for circulating water conduits) exposed to air-outdoor or Groundwater/soil. Freeze-thaw is not considered an aging mechanism for concrete components below the frost line (depth of 20 to 22 inches). The concrete associated with circulating water conduits is buried below the frost line and not subject to loss of material (spalling, scaling) and cracking due to freeze-thaw. See Subsection 3.5.2.2.2.3.1.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 050	Groups 6: concrete (inaccessible areas): all	Cracking due toexpansion from reaction with aggregates	Plant-specific aging management program or AMP XI.S6, “Structures Monitoring,” enhanced as necessary	Yes	Consistent with NUREG 2191. The Structures Monitoring program (B.2.1.33) will be used to manage cracking of the Group 6 inaccessible, reinforced concrete exposed to air – indoor uncontrolled, air - outdoor, Groundwater/soil, soil, water-flowing. See Subsection 3.5.2.2.2.3.2.
3.5-1, 051	Groups 6: concrete (inaccessible areas): exterior above- and below-grade; foundation;interior slab	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Plant-specific aging management program or AMP XI.S6, “Structures Monitoring,” enhanced as necessary	Yes	Consistent with NUREG 2191. The Structures Monitoring program (B.2.1.33) will be used to manage increase in porosity and permeability, loss of strength of the reinforced concrete Group 6 structures including that from inaccessible areas exposed to water-flowing, where the components include exterior above and below grade, foundation, or interior slab. See Subsection 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	Not Applicable. There are no Group 7 or Group 8 tanks with steel liners exposed to standing water in scope for this application. See Subsection 3.5.2.2.2.4.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 053	Support members; welds; bolted connections; support anchorage to building structure	Cumulative fatigue damage due to cyclic loading (Only if CLB fatigue analysis exists)	TLAA, SRP-SLR Section 4.3, “Metal Fatigue,” and/or Section 4.7, “Other Plant-Specific Time- Limited Aging Analyses”	Yes, TLAA	Fatigue is a TLAA; further evaluation is documented in Subsection 3.5.2.2.2.5. There are no support members; welds; bolted connections; or support anchorages to building structures subject to cumulative fatigue damage due to cyclic loading in Structures and Component Supports. However, this item number is applied to the refueling bellows support skirt as the material, environment, aging effect and aging management program are consistent with NUREG-2191 Volume 1.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 054	Concrete (accessibleareas): all	Cracking due toexpansion from reaction with aggregates	AMP XI.S6, “Structures Monitoring”	No	Consistent with NUREG-2191. The Structures Monitoring program (B.2.1.33) will be used to manage concrete cracking due to expansion from reaction with aggregates for elements exposed to air - indoor uncontrolled, air - outdoor, groundwater/soil, and water - flowing in the Reactor Buildings, Primary Containment Structures, Diesel Generator Buildings, Intake Pumping Station, Reinforced Concrete Chimney, Standby Gas Treatment Building, Off Gas Treatment Building, Equipment Access Lock, Vacuum Piping Building, Turbine Buildings, Radwaste Building, Service Building, Vent Vaults, Gate Structure No. 2, Gate Structure No. 3, Discharge Control Structures, Circulating Water Conduits, Diesel High Pressure Fire Protection House, Low Level Radwaste Storage Facility, Transformer Yard, 161 kV Switchyard, 500 kV Switchyard, Condensate Water Storage Tanks’ Foundations, Tunnels, and Trenches, Nitrogen Storage Tank Foundation, Supplemental Diesel Generator Building, Containment Atmospheric Dilution System Storage Tank Foundations,

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 054 (continued)					Residual Heat Removal Service Water Tunnels, Electric Cable Tunnel (From Intake Pumping Station to Powerhouse), Underground Concrete Encased Structures, Yard Structures (General), and South Access Retaining Walls.
3.5-1, 055	Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	AMP XI.S6, “Structures Monitoring”	No	Consistent with NUREG-2191. The Structures Monitoring program (B.2.1.33) will be used to manage reduction in concrete anchor capacity in building concrete at locations of expansion and grouted anchors, and grout pads for support base plates exposed to environments that include air – indoor uncontrolled and air - outdoor in the Structural Commodities Groups.
3.5-1, 056	Concrete: exterior above- and below- grade; foundation; interior slab	Loss of material due to abrasion; cavitation	AMP XI.S7, “Inspection of Water-Control Structures Associated with Nuclear Power Plants,” or the FERC/ US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants program (B.2.1.34) will be used to manage loss of material of the concrete in above and below grade exterior, foundation, and interior slab exposed to water - flowing in Gate Structure 3, Discharge Control Structure, and Circulating Water Conduits.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 057	Constant and variable load spring hangers; guides; stops	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	AMP XI.S3, “ASME Section XI, Subsection IWF”	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF program (B.2.1.30) will be used to manage loss of mechanical function of the steel constant and variable load spring hangers, guides, stops and sliding surfaces for ASME Class 1, 2, 3, and MC equipment supports exposed to air - indoor uncontrolled or air-outdoor.
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. The Inspection of Water- Control Structures Associated with Nuclear Power Plants program (B.2.1.34) will be used to monitor loss of material in components associated with the intake channel, north bank of the cool water channel, and the south dike of the cool water channel are exposed to environments of air – outdoor, water – flowing, and water - standing.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 059	Group 6: concrete (accessible areas): all	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	AMP XI.S7, “Inspection of Water-Control Structures Associated with Nuclear Power Plants,” or the FERC/ US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants program (B.2.1.34) will be used to manage cracking, loss of bond, and loss of material of accessible concrete elements of Group 6 Structures in the intake pumping station, Gate Structure No. 2 and 3, Discharge Control Structure, and Circulating Water Conduits exposed to air-outdoor, groundwater/soil, soil, and water-flowing in the Group 6 structures.
3.5-1, 060	Group 6: concrete (accessible areas): exterior above- and below-grade; foundation	Loss of material (spalling, scaling) andcracking due to freeze-thaw	AMP XI.S7, “Inspection of Water-Control Structures Associated with Nuclear Power Plants,” or the FERC/ US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants program (B.2.1.34) will be used to manage loss of material (spalling, scaling) and cracking of accessible concrete above- and below-grade exteriors, or foundations, exposed to environments that include air – outdoor and water - flowing in the Group 6 structures (except for circulating water conduits). The concrete associated with circulating water conduits is buried below the frost line and not subject to loss of material (spalling, scaling) and cracking due to freeze-thaw.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 061	Group 6: concrete (accessible areas): exterior above- and below-grade; foundation;interior slab	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	AMP XI.S7, “Inspection of Water-Control Structures Associated with Nuclear Power Plants,” or the FERC/ US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants program (B.2.1.34) will be used to manage increase in porosity and permeability and/or loss of strength of concrete in accessible concrete from Group 6 structures exposed environments that include air - indoor uncontrolled, air - outdoor, and water-flowing.
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 anddrying, 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. The components pertaining to this item are not in scope for this application at BFN.
3.5-1, 063	Groups 1-3, 5, 7-9: concrete (accessible areas): exterior above-and below-grade; foundation	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	AMP XI.S6, “Structures Monitoring”	No	Consistent with NUREG-2191. The Structures Monitoring program (B.2.1.33) will be used to manage increase in porosity and permeability, loss of strength of the concrete from exterior above and below grade or foundation exposed to water - flowing in Group 2, 3, 8, and 9 structures.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 064	Groups 1-3, 5, 7-9: concrete (accessible areas): exterior above-and below-grade; foundation	Loss of material (spalling, scaling) andcracking due to freeze-thaw	AMP XI.S6, “Structures Monitoring”	No	Consistent with NUREG-2191. The Structures Monitoring program (B.2.1.33) will be used to manage cracking and loss of material of the concrete elements of Group 2, 3, 8, and 9 structures exposed to air-outdoor. At BFN, there are no stand-alone Group 1 or 5 structures, and Group 7 structures are not applicable to BFN.
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 ofmaterial (spalling,scaling) due to corrosion of embedded steel	AMP XI.S6, “Structures Monitoring”	No	Consistent with NUREG-2191. The Structures Monitoring program (B.2.1.33) will be used to manage cracking, loss of bond, and loss of material for concrete elements in Groups 2, 3, 8, and 9 at accessible and inaccessible areas of the concrete below- grade exterior or foundation, as well as for concrete in Group 6 inaccessible areas. The environments that the applicable components are exposed to include air - outdoor, and groundwater/soil. At BFN, there are no stand-alone Group 1 or 5 structures, and Group 7 structures are not applicable to BFN.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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. The Structures Monitoring program (B.2.1.33) will be used to manage cracking, loss of bond, and loss of material for concrete elements in Groups 2, 3, 8, and 9 at accessible areas of the concrete that is interior or above- grade exterior. At BFN, there are no stand-alone Group 1 or 5 structures, and Group 7 structures are not applicable to BFN.
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 chemicalattack	AMP XI.S6, “Structures Monitoring”	No	Consistent with NUREG-2191. The Structures Monitoring program (B.2.1.33) will be used to manage increase in porosity and permeability, cracking, or loss of material for concrete elements in Groups 2, 3, 8, and 9 at interior; above-grade exterior or inaccessible areas containing below-grade exterior or foundation as well as for concrete in Group 6 areas. The environments that the applicable components are exposed to include air - indoor uncontrolled, air - outdoor, and groundwater/ soil. At BFN, there are no stand-alone Group 1 or 5 structures, and Group 7 structures are not applicable to BFN.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 068	High-strength steel structural bolting	Cracking due to SCC	AMP XI.S3, "ASME Section XI, Subsection IWF"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF program (B.2.1.30) will be used to manage cracking of the high strength steel bolting with yield strength of 150 ksi or greater used in supports for piping and piping supports exposed to air in the Structural Commodities Group: piping and piping supports.
3.5-1, 069	This Item Number is not listed in NUREG-2191 Vol 1 and was deleted from NUREG-2192.				
3.5-1, 070	Masonry walls: all	Cracking due to restraint shrinkage, creep, aggressive environment	AMP XI.S5, "Masonry Walls"	No	Consistent with NUREG 2191. The Masonry Walls program (B.2.1.32) will be used to manage cracking of the masonry walls exposed to air - indoor uncontrolled in the Reactor Buildings, Diesel Generator Buildings, Intake Pumping Station, Reinforced Concrete Chimney, Off Gas Treatment Building, Turbine Buildings, Radwaste Building, and Service Building.
3.5-1, 071	Masonry walls: all	Loss of material (spalling, scaling) andcracking due to freeze-thaw	AMP XI.S5, "Masonry Walls"	No	Not applicable. BFN does not have any masonry walls exposed to air – outdoors or that are susceptible to the effects of loss of material (spalling, scaling) and cracking due to freeze-thaw.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 072	Seals; gasket; moisture barriers (caulking, flashing, and other sealants)	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	AMP XI.S6, "Structures Monitoring"	No	Consistent with NUREG 2191. The Structures Monitoring program (B.2.1.33) will be used to manage loss of sealing of the Structural Commodities Groups items (i.e., moisture barriers, seals, or gaskets) exposed to air - indoor uncontrolled or air - outdoor.
3.5-1, 073	Service Level I coatings	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting,or physical damage	AMP XI.S8, "Protective Coating Monitoring and Maintenance"	No	Consistent with NUREG-2191. The Protective Coating Monitoring and Maintenance program (B.2.1.35) will be used to manage loss of coating or lining integrity of the Service Level I Coatings exposed to treated water or air-indoor uncontrolled in the Containment Structure.
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. The Structures Monitoring program (B.2.1.33) will be used to manage the loss of mechanical function of the sliding support bearings and sliding support surfaces in the Tube Track Structural Commodities Group exposed to Air-indoor uncontrolled and Air-outdoor.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 075	Sliding surfaces	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	AMP XI.S3, "ASME Section XI, Subsection IWF"	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF program (B.2.1.30) will be used to manage the loss of mechanical function of the sliding surfaces in the Equipment Supports and Foundations and Piping Supports Structural Commodities Groups for ASME Class 1, 2, 3, and MC structures and component supports, exposed to air- indoor uncontrolled.
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	Consistent with NUREG-2191. The Structures Monitoring program (B.2.1.33) will be used to manage loss of mechanical function on sliding surfaces such as the radial beam seats in the BWR drywell. However, Lubrite is not susceptible to lockup due to wear, thus this mechanism is not applicable for combinations including the Lubrite material.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	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. The Structures Monitoring program (B.2.1.33) will be used to manage loss of material in steel element types such as general structural steel components, metal roofing, metal siding, hatches/plugs, controlled leakage doors, compressible joints, and penetrations that are exposed to air-indoor uncontrolled and air-outdoor. These components are found in the Reactor Buildings, Primary Containment structures, Diesel Generator buildings, Reinforced Concrete Chimney, Equipment Access Lock, Turbine Buildings, Radwaste Building, Service Building, Gate Structure No.2 And 3, Circulating Water Conduits, Diesel High Pressure Fire Protection House, Low Level Radwaste Storage Facility, Transformer Yard, 161 kV Switchyard, 500 kV Switchyard, Condensate Water Storage Tanks’ Foundations, Trenches, and Tunnels, Supplemental Diesel Generator Building, Residual Heat Removal Service Water Tunnels, Underground Concrete Encased Structures, and areas containing the

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 077 (continued)					Structural Commodities Groups of Hazard Barriers and Elastomers, Miscellaneous Steel, and Penetration and Sleeves.
3.5-1, 078	Stainless steel fuel pool liner	Cracking due to SCC; Loss of material due to pitting and crevice corrosion	AMP XI.M2, “Water Chemistry,” and monitoring of the spent fuel pool water level and leakage from the leak chase channels.	No	Consistent with NUREG-2191. The Water Chemistry program (B.2.1.2) (in addition to monitoring of the spent fuel pool leakage water level and leakage from the leak chase channels) will be used to manage cracking and loss of material of the stainless steel fuel pool liner exposed to treated water in the Reactor Building.
3.5-1, 079	Steel components: piles	Loss of material due to corrosion	AMP XI.S6, “Structures Monitoring”	No	Consistent with NUREG-2191. The Structures Monitoring program (B.2.1.33) will be used to manage loss of material of the steel piles exposed to groundwater/soil in the Pilings Structural Commodities Group.
3.5-1, 080	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S6, “Structures Monitoring”	No	Consistent with NUREG-2191. The Structures Monitoring program (B.2.1.33) will be used to manage loss of material of steel structural bolting exposed to air - indoor uncontrolled and air - outdoor environments in the applicable buildings, structures, and components.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 081	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S3, “ASME Section XI, Subsection IWF”	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF program (B.2.1.30) will be used to manage loss of material of the steel structural bolting used with ASME Class 1, 2, 3, and MC supports exposed to air-indoor uncontrolled or air-outdoor.
3.5-1, 082	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S6, “Structures Monitoring”	No	Consistent with NUREG-2191. The Structures Monitoring program (B.2.1.33) will be used to manage loss of material of the steel bolting exposed to air – outdoor in the applicable buildings, structures, and components.
3.5-1, 083	Structural bolting	Loss of material due to general, pitting, crevice corrosion	AMP XI.S7, “Inspection of Water-Control Structures Associated with Nuclear Power Plants,” or the FERC/ US Army Corp of Engineers dam inspections and maintenance programs.	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants program (B.2.1.34) will be used to manage loss of material of steel bolting in the Intake Pumping Station, Gate Structure No. 3, and as a basis for Group 6 component, material, environment combinations in the Intake Pumping Station and Structural Commodities Groups (Hazard Barriers and Elastomers, Miscellaneous Steel, Penetrations and Sleeves, and Pilings) exposed to air-indoor uncontrolled, air - outdoor, water-flowing).
3.5-1, 084	This Item Number is not listed in NUREG-2191 Vol 1 and was deleted from NUREG-2192.				

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 085	Structural bolting	Loss of material due to pitting, crevice corrosion	AMP XI.M2, “Water Chemistry,” and AMP XI.S3, “ASME Section XI, Subsection IWF”	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF program (B.2.1.30) and Water Chemistry program (B.2.1.2) will be used to manage loss of material of the stainless steel structural bolting used for supports for ASME Class 1, Class 2, and Class 3 piping and component supports exposed to treated water and in the following Structural Commodities Group: Piping Supports.
3.5-1, 086	Structural bolting	Loss of material due to pitting, crevice corrosion	AMP XI.S3, “ASME Section XI, Subsection IWF”	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF program (B.2.1.30) will be used to manage loss of material in galvanized steel and steel bolting for ASME Class 2 and 3 piping and components exposed to air- outdoor in the following Structural Commodities Group: Piping Supports.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 087	Structural bolting	Loss of preload due to self-loosening	AMP XI.S3, “ASME Section XI, Subsection IWF”	No	Consistent with NUREG-2191. The ASMESection XI, Subsection IWF program (B.2.1.30) will be used to manage loss of preload of the galvanized steel, stainless steel, and steel bolting, used in ASME Class 1, 2, 3, and MC supports exposed to air - indoor uncontrolled, air - outdoor, concrete, groundwater/soil, water-flowing, water-standing in the in the following Structural Commodities Groups: Equipment Supports and Foundations; Penetration and Sleeves; and Piping Supports.
3.5-1, 088	Structural bolting	Loss of preload due to self-loosening	AMP XI.S6, “Structures Monitoring”	No	Consistent with NUREG-2191. The Structures Monitoring program (B.2.1.33) will be used to manage loss of preload for bolting made from steel, galvanized steel, stainless steel, and aluminum exposed to air-indoor uncontrolled, air- outdoor, concrete, condensation, groundwater/soil, treated water, water-flowing, and water-standing.
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	Not Applicable. This Item Number is not applicable to the BFN Mark I steel containment.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 090	Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to general (steel only), pitting, crevicecorrosion	AMP XI.M2, “Water Chemistry,” and AMP XI.S3, “ASME Section XI, Subsection IWF”	No	The ASME Section XI, Subsection IWF program (B.2.1.30) and Water Chemistry program (B.2.1.2) will be used to manage loss of material of the steel and stainless steel support members, welds, bolted connections, and support anchorage to building structure. This Item Number consists of ASME Class 1 piping and component supports exposed to treated water classified in Structural Commodities Groups.
3.5-1, 091	Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to general, pitting corrosion	AMP XI.S3, “ASME Section XI, Subsection IWF”	No	Consistent with NUREG-2191. The ASME Section XI, Subsection IWF program (B.2.1.30) will be used to manage loss of material of the steel ASME Class 1, 2, 3, and MC supports exposed to air - indoor uncontrolled and air - outdoor in the Structural Commodities Groups.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 092	Support members; welds; bolted connections; support anchorage to building structure	Loss of material due to general, pitting corrosion	AMP XI.S6, “Structures Monitoring”	No	Consistent with NUREG-2191. The Structures Monitoring program (B.2.1.33) will be used to manage loss of material of the steel supports for Cable Trays and Supports, Conduit and Conduit Supports, Electrical Panels, Racks, Cabinet, and Other Enclosures, Equipment Supports and Foundations, HVAC Duct Supports, Miscellaneous Steel, Penetrations and Sleeves, Pipe Whip Restraints, Piping Supports, and Tube Track exposed to air - indoor uncontrolled or air - outdoor in the Structural Commodities Groups.
3.5-1, 093	Galvanized steel support members; welds; bolted connections; support anchorage to building structure	Loss of material due to pitting, crevice corrosion	AMP XI.S6, “Structures Monitoring”	No	Consistent with NUREG-2191. The Structures Monitoring program (B.2.1.33) will be used to manage loss of material of galvanized steel support members; welds; bolted connections; support anchorage to building structures exposed to air - outdoor in the Structural Commodities Groups.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 094	Vibration isolation elements	Reduction or loss of isolation function due to radiation hardening, temperature, humidity, sustained vibratory loading	AMP XI.S3, “ASME Section XI, Subsection IWF,” and/or AMP XI.S6, “Structures Monitoring”	No	Consistent with NUREG-2191. The Structures Monitoring program (B.2.1.33) will be used to manage reduction or loss of isolation function of the elastomer supports for vibration isolation elements exposed to air- indoor uncontrolled in the Structural Commodities Group: Equipment Supports and Foundations.
3.5-1, 095	Galvanized steel support members; welds; bolted connections; support anchorage to building structure	None	None	No	Consistent with NUREG-2191 for all component types in the following Structural Commodities Groups: Cable Trays and Supports, Conduit and Conduit Supports, Electrical Panels, Racks, Cabinets, and Other Enclosures, Equipment Supports And Foundations, HVAC Duct Supports, Miscellaneous Steel, Penetrations and Sleeves, Pipe Whip Restraints and Jet Impingement Shields, Piping Supports, and Tube Track.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.5-1, 096	Groups 6: concrete (accessible areas): all	Cracking due to expansion from reaction with aggregates	AMP XI.S7, “Inspection of Water-Control Structures Associated with Nuclear Power Plants”	No	Consistent with NUREG-2191. The Inspection of Water-Control Structures Associated with Nuclear Power Plants program (B.2.1.34) will be used to manage cracking of the concrete in Group 6 accessible areas of the Intake Pumping Station, Gate Structure No. 2, Gate Structure No. 3, Discharge Control Structure, and Circulating Water Conduits exposed to air- indoor uncontrolled, air - outdoor, and water - flowing.
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	The Structures Monitoring program (B.2.1.33) will be used to manage reduction of strength and loss of mechanical properties of the reinforced concrete elements exposed to the specified environment (air-indoor uncontrolled) in the Group 4 structure. See Subsection 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	Not Applicable. This item is not applicable because it is a borated water related issue that applies to PWR, and BFN is a BWR.

Table 3.5.1, Summary of Aging Management Evaluations for the Containments, Structures and Component Supports (Continued)

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage loss of material due to pitting and crevice corrosion, cracking due to SCC for aluminum, stainless steel support members; welds; bolted connections; support anchorage to the building structure. This Item Number is applicable to components that are classified as Class 1, 2, 3 or MC and are exposed to an environment of air or condensation. See Subsection 3.5.2.2.2.4.
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	Consistent with NUREG-2191. The One-Time Inspection program (B.2.1.20) will be used to manage loss of material due to pitting and crevice corrosion or cracking due to SCC for components exposed to an environment of air and condensation. See Subsection 3.5.2.2.2.4.

Table 3.5.2-1, Reactor Buildings - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): foundation	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A2.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A2.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier, HELB Shielding	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A2.TP-204	3.5-1, 043	A

Table 3.5.2-1, Reactor Buildings - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete (inaccessible areas): all	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A2.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier, HELB Shielding	Concrete	Condensation	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A2.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier, HELB Shielding	Concrete	Groundwater	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A2.TP-204	3.5-1, 043	A

Table 3.5.2-1, Reactor Buildings - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): all	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier, HELB Shielding	Concrete	Treated water	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A2.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A2.TP-204	3.5-1, 043	A
Concrete: all	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier	Concrete	Soil	None	None	III.A2.TP-30	3.5-1, 044	I, 1

Table 3.5.2-1, Reactor Buildings - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): exterior above and below-grade; foundation	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier, HELB Shielding	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A2.TP-67	3.5-1, 047	G, 4
Concrete (inaccessible areas): exterior above and below-grade; foundation	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier	Concrete	Air - outdoor	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A2.TP-67	3.5-1, 047	G, 4
Concrete (inaccessible areas): exterior above and below-grade; foundation	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier, HELB Shielding	Concrete	Condensation	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A2.TP-67	3.5-1, 047	G, 4

Table 3.5.2-1, Reactor Buildings - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): exterior above and below-grade; foundation	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier, HELB Shielding	Concrete	Groundwater	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A2.TP-67	3.5-1, 047	G, 4
Concrete (inaccessible areas): exterior above and below-grade; foundation	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier, HELB Shielding	Concrete	Treated Water	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A2.TP-67	3.5-1, 047	G, 4
Concrete (inaccessible areas): exterior above and below-grade; foundation	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier, HELB Shielding	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A2.TP-67	3.5-1, 047	A

Table 3.5.2-1, Reactor Buildings - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): all	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier, HELB Shielding	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A2.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A2.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier, HELB Shielding	Concrete	Condensation	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A2.TP-25	3.5-1, 054	A

Table 3.5.2-1, Reactor Buildings - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): all	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier, HELB Shielding	Concrete	Groundwater	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A2.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier, HELB Shielding	Concrete	Treated water	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A2.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior above and below-grade; foundation	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier, HELB Shielding	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A2.TP-24	3.5-1, 063	A

Table 3.5.2-1, Reactor Buildings - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): exterior below grade; foundation	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier, HELB Shielding	Concrete	Condensation	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A2.TP-24	3.5-1, 063	G, 4
Concrete (accessible areas): exterior below grade; foundation	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier, HELB Shielding	Concrete	Groundwater	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A2.TP-24	3.5-1, 063	G, 4
Concrete (accessible areas): exterior below grade; foundation	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier, HELB Shielding	Concrete	Treated water	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A2.TP-24	3.5-1, 063	G, 4

Table 3.5.2-1, Reactor Buildings - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): exterior above and below-grade; foundation	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A2.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): below-grade exterior; foundation	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A2.TP-212	3.5-1, 065	A
Concrete (accessible areas): interior	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier, HELB Shielding	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A2.TP-26	3.5-1, 066	A

Table 3.5.2-1, Reactor Buildings - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): Above grade exterior	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A2.TP-26	3.5-1, 066	A
Concrete: interior	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier, HELB Shielding	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A2.TP-28	3.5-1, 067	A
Concrete: Above grade exterior	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A2.TP-28	3.5-1, 067	A

Table 3.5.2-1, Reactor Buildings - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): below-grade exterior; foundation	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier, HELB Shielding	Concrete	Treated water	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A2.TP-29	3.5-1, 067	G, 4
Concrete (inaccessible areas): below-grade exterior; foundation	Flood Barrier, Shelter and Protection, Pressure Boundary, Shielding, Structural Support, Missile Barrier	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A2.TP-29	3.5-1, 067	A
Masonry walls: all: interior	Shelter and Protection, Shielding, Structural Support	Concrete block	Air - indoor uncontrolled	Cracking due to restraint shrinkage, creep, and aggressive environment	Masonry Walls (B.2.1.32)	III.A2.T-12	3.5-1, 070	A
Polyurethane Foam Between the Drywell and the Reactor Building Concrete	Expansion / separation	Polyurethane Foam	Embedded/ encased	Radiation embrittlement; hardening, loss of strength due to elastomer degradation	Section 4.7, “Other Plant-Specific Time-Limited Aging Analyses”	N/A	N/A	J, 3
Stainless steel fuel pool liner	Structural Support	Stainless steel	Concrete	None	None	V.F.EP-20	3.2-1, 091	C

Table 3.5.2-1, Reactor Buildings - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Stainless steel fuel pool liner	Structural Support, Water Retaining Boundary	Stainless steel	Treated water	Cracking due to SCC; loss of material due to pitting and crevice corrosion	Water Chemistry (B.2.1.2) and monitoring of the spent fuel pool water level and leakage from the leak chase channels	III.A5.T-14	3.5-1, 078	A
Stainless steel fuel pool liner	Structural Support, Water Retaining Boundary	Stainless steel	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5-1, 100	C
Spent fuel pool gates	Water Retaining Boundary	Aluminum	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5-1, 100	C
Spent fuel pool gates	Water Retaining Boundary	Aluminum	Treated Water	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.A4.AP-130	3.3-1, 025	C
Spent fuel pool gates	Water Retaining Boundary	Stainless steel	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5-1, 100	C
Spent fuel pool gates	Water Retaining Boundary	Stainless steel	Treated Water	Cracking due to SCC; loss of material due to pitting and crevice corrosion	Water Chemistry (B.2.1.2) and monitoring of the spent fuel pool water level and leakage from the leak chase channels	III.A5.T-14	3.5-1, 078	C
Spent fuel pool gates bolting	Water Retaining Boundary	Aluminum	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5-1, 100	C

Table 3.5.2-1, Reactor Buildings - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Spent fuel pool gates bolting	Water Retaining Boundary	Aluminum	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A
Spent fuel pool gates bolting	Water Retaining Boundary	Aluminum	Treated Water	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and One-Time Inspection (B.2.1.20)	VII.A4.AP-130	3.3-1, 025	C
Spent fuel pool gates bolting	Water Retaining Boundary	Aluminum	Treated Water	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A
Spent fuel pool gates bolting	Water Retaining Boundary	Stainless steel	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5-1, 100	C
Spent fuel pool gates bolting	Water Retaining Boundary	Stainless steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A
Spent fuel pool gates bolting	Water Retaining Boundary	Stainless steel	Treated Water	Cracking due to SCC; loss of material due to pitting and crevice corrosion	Water Chemistry (B.2.1.2) and monitoring of the spent fuel pool water level and leakage from the leak chase channels	III.A5.T-14	3.5-1, 078	C
Spent fuel pool gates bolting	Water Retaining Boundary	Stainless steel	Treated Water	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A
Steel components: all structural steel	Structural Support	Steel	Concrete	None	None	II.B1.1.CP-44	3.5-1, 041	C

Table 3.5.2-1, Reactor Buildings - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Steel components: all structural steel	Pressure Boundary, Shelter and Support, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A2.TP-302	3.5-1, 077	A
Steel components: all structural steel	Pressure Boundary, Shelter and Support, Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A2.TP-302	3.5-1, 077	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A2.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A2.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A2.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A2.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Concrete	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Condensation	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A, 4

Table 3.5.2-1, Reactor Buildings - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural bolting	Structural Support	Galvanized Steel	Groundwater	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A, 4
Structural bolting	Structural Support	Galvanized Steel	Treated water	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A, 4
Structural bolting	Structural Support	Non-ferrous - aluminum	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A, 2
Structural bolting	Structural Support	Non-ferrous - aluminum	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Non-ferrous - aluminum	Condensation	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A, 2, 4
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Concrete	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Condensation	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A, 4
Structural bolting	Structural Support	Steel	Groundwater	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A, 4
Structural bolting	Structural Support	Steel	Treated water	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A, 4

Table 3.5.2-1 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. Cracks, distortion, increase in component stress level due to settlement are not aging effects requiring management for structures founded on rock or bearing piles. See Subsection 3.5.2.2.2.1.3.
2. The reactor building blow-out panels use aluminum explosive bolts.
3. The polyurethane foam is attached to the Drywell on one side and separated from the reactor building concrete by fiberglass laminate forms on the other. In accordance with the BFN current licensing basis, the effect of a postulated increase in the polyurethane foam stiffness resulting from radiation dose is evaluated as a TLAA in Section 4.7.2.
4. The reactor building is exposed to condensation, groundwater, treated water. The listed combination was screened in to conservatively capture all potential combinations that stem from these environments.

Table 3.5.2-2, Primary Containment Structures - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): all	HELB Shielding, Shielding, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A4.TP-204	3.5-1, 043	A
Concrete (accessible areas): all	HELB Shielding, Shielding, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A4.TP-25	3.5-1, 054	A
Concrete (accessible areas): interior	HELB Shielding, Shielding, Structural Support	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A4.TP-26	3.5-1, 066	A
Concrete: interior	HELB Shielding, Shielding, Structural Support	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A4.TP-28	3.5-1, 067	A
High Density Shielding Concrete	HELB Shielding, Shielding, Structural Support	Concrete	Air - indoor uncontrolled	Reduction of strength; loss of mechanical properties due to irradiation (i.e., radiation interactions with material and radiation-induced heating)	Structures Monitoring (B.2.1.33)	III.A4.T-35	3.5-1, 097	C, 1

Table 3.5.2-2, Primary Containment Structures - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Group 4: Concrete (reactor cavity area proximate to the reactor vessel): reactor (primary /biological) shield wall; sacrificial shield wall; reactor vessel support / pedestal structure	HELB Shielding, Shielding, Structural Support	Concrete	Air - indoor uncontrolled	Reduction of strength; loss of mechanical properties due to irradiation (i.e., radiation interactions with material and radiation-induced heating)	Structures Monitoring (B.2.1.33)	III.A4.T-35	3.5-1, 097	A
Metal liner; Metal plate	Pressure Boundary, Structural Support, Shelter and Protection	Steel	Air - indoor uncontrolled	None	None	II.B4.CP-37	3.5-1, 027	I, 5
Penetration bellows	Expansion/ Separation, Pressure Boundary	Stainless steel; dissimilar metal welds	Air - indoor uncontrolled	Cumulative fatigue damage due to fatigue (Only if CLB fatigue analysis exists)	Section 4.6, “Primary Containment Fatigue Analyses”	II.B4.C-13	3.5-1, 009	A
Penetration bellows	Expansion/ Separation, Pressure Boundary	Stainless steel; dissimilar metal welds	Air - indoor uncontrolled	Cracking due to SCC	ASME Section XI, Subsection IWE (B.2.1.29) and 10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-38	3.5-1, 010	A
Airlock	Pressure Boundary, Structural Support, Shelter and Protection	Steel	Air - indoor uncontrolled	None	None	II.B4.C-37	3.5-1, 027	I, 5
Personnel airlock	Pressure Boundary, Structural Support, Shelter and Protection	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	ASME Section XI, Subsection IWE (B.2.1.29) and 10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.C-16	3.5-1, 028	A

Table 3.5.2-2, Primary Containment Structures - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Personnel airlock: locks, hinges, closure mechanisms	Pressure Boundary, Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of leak tightness due to mechanical wear	ASME Section XI, Subsection IWE (B.2.1.29) and 10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-39	3.5-1, 029	A
Pressure retaining bolting	Pressure Boundary, Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	ASME Section XI, Subsection IWE (B.2.1.29) and 10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-150	3.5-1, 030	A
Pressure retaining bolting	Pressure Boundary, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-148	3.5-1, 031	A
Service Level I coatings	Maintain adhesion	Service Level I coatings	Air - indoor uncontrolled	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, physical damage	Protective Coating Monitoring and Maintenance (B.2.1.35)	II.B4.CP-152	3.5-1, 034	A
Service Level I coatings	Maintain adhesion	Service Level I coatings	Treated water	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, physical damage	Protective Coating Monitoring and Maintenance (B.2.1.35)	II.B4.CP-152	3.5-1, 034	A
Service Level I coatings	Maintain adhesion	Service Level I coatings	Air - indoor uncontrolled	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, physical damage	Protective Coating Monitoring and Maintenance (B.2.1.35)	III.A4.TP-301	3.5-1, 073	A

Table 3.5.2-2, Primary Containment Structures - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Service Level I coatings	Maintain adhesion	Service Level I coatings	Treated water	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, physical damage	Protective Coating Monitoring and Maintenance (B.2.1.35)	III.A4.TP-301	3.5-1, 073	A
Sliding surfaces: graphite impregnated base plates	Structural Support	Graphite	Air - indoor uncontrolled	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	Structures Monitoring (B.2.1.33)	III.B4.TP-46	3.5-1, 075	C
Sliding surfaces	Structural Support	Molykote® 321 or equal	Air - indoor uncontrolled	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-45	3.5-1, 075	F, 2
Sliding surfaces: radial beam seats in BWR drywell	Structural Support	Lubrite®	Air - indoor uncontrolled	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload	Structures Monitoring (B.2.1.33)	III.A4.TP-35	3.5-1, 076	A, 3
Steel components: all structural steel	Structural Support	Steel	Concrete	None	None	II.B1.1.CP-44	3.5-1, 041	C
Steel components: all structural steel	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A4.TP-302	3.5-1, 077	A
Steel components: all structural steel	Structural Support	Steel	Treated water	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A4.TP-302	3.5-1, 077	G, 6
Steel elements (accessible areas): drywell shell; drywell head; drywell shell in sand pocket regions	Pressure Boundary, Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	ASME Section XI, Subsection IWE (B.2.1.29) and 10 CFR Part 50, Appendix J (B.2.1.31)	II.B1.1.CP-43	3.5-1, 035	A

Table 3.5.2-2, Primary Containment Structures - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Steel elements (accessible areas): drywell shell; drywell shell in sand pocket regions	Pressure Boundary, Shelter and Protection, Structural Support	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion	ASME Section XI, Subsection IWE (B.2.1.29) and 10 CFR Part 50, Appendix J (B.2.1.31)	II.B1.1.CP-43	3.5-1, 035	G, 6
Steel elements: drywell head; downcomers	Pressure Boundary, Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to mechanical wear, including fretting	ASME Section XI, Subsection IWE (B.2.1.29)	II.B1.1.C-23	3.5-1, 036	A
Steel elements: downcomers	Pressure Boundary, Structural Support	Steel	Treated water	Loss of material due to mechanical wear, including fretting	ASME Section XI, Subsection IWE (B.2.1.29)	II.B1.1.C-23	3.5-1, 036	G, 6
Steel elements: drywell support skirt	Structural Support	Steel	Concrete	None	None	II.B1.1.CP-44	3.5-1, 041	A
Steel elements: refueling bellows support skirt	Water retaining boundary	Steel	Air - indoor uncontrolled	Cumulative fatigue damage due to fatigue (Only if CLB fatigue analysis exists)	Section 4.3, “Metal Fatigue”	III.B1.3.T-26	3.5-1, 053	C
Steel elements: refueling bellows assemblies	Water retaining boundary	Stainless Steel	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B4.T-37a	3.5-1, 100	J, 4
Steel elements: refueling bellows assemblies	Water retaining boundary	Stainless Steel	Treated water	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B4.T-37a	3.5-1, 100	J, 4

Table 3.5.2-2, Primary Containment Structures - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Steel elements: torus shell	Pressure Boundary, Structural Support, Water Retaining Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	ASME Section XI, Subsection IWE (B.2.1.29) and 10 CFR Part 50, Appendix J (B.2.1.31)	II.B1.1.CP-48	3.5-1, 006	A
Steel elements: torus shell	Pressure Boundary, Structural Support, Water Retaining Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion	ASME Section XI, Subsection IWE (B.2.1.29) and 10 CFR Part 50, Appendix J (B.2.1.31)	II.B1.1.CP-48	3.5-1, 006	A
Steel elements: torus ring girders; downcomers	Pressure Boundary, Structural Support, Water Retaining Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	ASME Section XI, Subsection IWE (B.2.1.29)	II.B1.1.CP-109	3.5-1, 007	A
Steel elements: downcomers	Pressure Boundary, Structural Support, Water Retaining Boundary	Steel	Treated water	Loss of material due to general, pitting, crevice corrosion	ASME Section XI, Subsection IWE (B.2.1.29)	II.B1.1.CP-109	3.5-1, 007	A
Steel elements: vent header	Direct Flow, Pressure Boundary, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	ASME Section XI, Subsection IWE (B.2.1.29)	II.B1.1.CP-109	3.5-1, 007	C
Steel elements: torus vent header; downcomers	Direct Flow, Pressure Boundary, Structural Support	Steel	Air - indoor uncontrolled	Cumulative fatigue damage due to fatigue (Only if CLB fatigue analysis exists)	Section 4.6, “Primary Containment Fatigue Analyses”	II.B1.1.C-21	3.5-1, 009	A

Table 3.5.2-2, Primary Containment Structures - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Steel elements: vent line bellows	Direct Flow, Expansion/ Separation, Pressure Boundary, Structural Support	Steel; stainless steel	Air - indoor uncontrolled	Cumulative fatigue damage due to fatigue (Only if CLB fatigue analysis exists)	Section 4.6, “Primary Containment Fatigue Analyses”	II.B1.1.C-21	3.5-1, 009	A
Steel elements: vent line bellows	Direct Flow, Expansion/ Separation, Pressure Boundary, Structural Support	Stainless steel	Air - indoor uncontrolled	Cracking due to SCC	ASME Section XI, Subsection IWE (B.2.1.29) and 10 CFR Part 50, Appendix J (B.2.1.31)	II.B1.1.CP-50	3.5-1, 039	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A4.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A4.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Concrete	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A4.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Treated water	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A4.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A4.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Concrete	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A4.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Treated water	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A4.TP-261	3.5-1, 088	A

<u>Table 3.5.2-2 Notes</u>

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.

B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.

C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.

D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.

F. Material not in NUREG-2191 for this component.

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.

Plant Specific Notes

1. High density shielding concrete is un-reinforced concrete encased between structural steel plates and is inaccessible. See Subsection 3.5.2.2.2.6.
2. Molykote 321® (or equal) is a sliding surface coating material that is potentially subject to loss of mechanical function. The ASME Section XI, Subsection IWF program (B.2.1.30) manages the aging of this material.
3. Lubrite is not susceptible to lockup due to wear. However, the Structures Monitoring program (B.2.1.33) will continue to monitor the loss of mechanical function due to corrosion, distortion, dirt or debris accumulation,
4. The One-Time Inspection program (B.2.1.20) will manage aging effects related to the refueling bellows as there is no plant specific OE indicating SSC of refueling bellows.
5. A plant-specific further evaluation was performed on the noted components (metal liner, metal plate, airlock, equipment hatch, CRD hatch, and penetration sleeves) to demonstrate that cracking due to cyclic loading is an aging effect that does not require aging management for the components. The option to perform a fatigue waiver was used in lieu of managing for cracking due to cyclic loading with the 10 CFR Part 50, Appendix J program (B.2.1.31) and ASME Section XI, Subsection IWE program (B.2.1.29) via supplemental surface examinations or leak rate test.

6. The drywell shell, downcomers, and supports for vent system consist of steel and are exposed to treated water and subject to loss of material due to corrosion. The Structures Monitoring program (B.2.1.33) will manage the aging of this material.

Table 3.5.2-3, Diesel Generator Buildings - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete (inaccessible areas): foundation	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A

Table 3.5.2-3, Diesel Generator Buildings - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: all	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Soil	Cracking and distortion due to increased stress levels from settlement	Structures Monitoring (B.2.1.33)	III.A3.TP-30	3.5-1, 044	A
Concrete (inaccessible areas): exterior above and below-grade; foundation	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5-1, 047	A
Concrete (accessible areas): all	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior above and below-grade; foundation	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-24	3.5-1, 063	A

Table 3.5.2-3, Diesel Generator Buildings - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): exterior above and below grade; foundation	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): below-grade exterior; foundation	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5-1, 065	A
Concrete (accessible areas): interior	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete (accessible areas): above grade exterior	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete: interior	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A

Table 3.5.2-3, Diesel Generator Buildings - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: above grade exterior	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete (inaccessible areas): below-grade exterior; foundation	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5-1, 067	A
Masonry walls: all	Shelter and Protection, Structural Support	Concrete block	Air - indoor uncontrolled	Cracking due to restraint shrinkage, creep, and aggressive environment	Masonry Walls (B.2.1.32)	III.A3.T-12	3.5-1, 070	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A

Table 3.5.2-3, Diesel Generator Buildings - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Galvanized steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A

<u>Table 3.5.2-3 Notes</u>

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None

Table 3.5.2-4, Intake Pumping Station - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Soil	None	None	III.A6.TP-30	3.5-1, 044	I, 1
Concrete (inaccessible areas): exterior above grade	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A6.TP-110	3.5-1, 049	A, 2
Concrete (inaccessible areas): exterior above- and below grade; foundation	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A6.TP-110	3.5-1, 049	A, 2
Concrete (inaccessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-220	3.5-1, 050	A
Concrete (inaccessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-220	3.5-1, 050	A
Concrete (inaccessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-220	3.5-1, 050	A

Table 3.5.2-4, Intake Pumping Station - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-220	3.5-1, 050	A
Concrete (inaccessible areas): exterior above and below-grade; foundation; interior slab	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A6.TP-109	3.5-1, 051	A
Concrete (accessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-38	3.5-1, 059	A
Concrete (accessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-38	3.5-1, 059	A

Table 3.5.2-4, Intake Pumping Station - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Water - flowing	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-38	3.5-1, 059	A
Concrete (accessible areas): exterior above and below-grade; foundation	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-36	3.5-1, 060	A
Concrete (accessible areas): exterior above and below-grade; foundation	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Water - flowing	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-36	3.5-1, 060	A
Concrete (accessible areas): foundation; interior slab	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-37	3.5-1, 061	A
Concrete (accessible areas): exterior above and below-grade; foundation	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-37	3.5-1, 061	A
Concrete (accessible areas): exterior above and below-grade; foundation	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Water - Flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-37	3.5-1, 061	A

Table 3.5.2-4, Intake Pumping Station - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A6.TP-104	3.5-1, 065	A
Concrete (inaccessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A6.TP-104	3.5-1, 065	A
Concrete (inaccessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A6.TP-104	3.5-1, 065	A
Concrete (accessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	C
Concrete (accessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	C
Concrete (inaccessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A6.TP-107	3.5-1, 067	A

Table 3.5.2-4, Intake Pumping Station - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-34	3.5-1, 096	A
Concrete (accessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-34	3.5-1, 096	A
Concrete (accessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-34	3.5-1, 096	A
Masonry walls: all	Shelter and Protection, Structural Support	Concrete block	Air - indoor uncontrolled	Cracking due to restraint shrinkage, creep, and aggressive environment	Masonry Walls (B.2.1.32)	III.A6.T-12	3.5-1, 070	A
Steel components: all structural steel	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A6.TP-248	3.5-1, 080	C
Steel components: all structural steel	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A6.TP-248	3.5-1, 080	C
Steel components: all structural steel	Structural Support	Steel	Water - flowing	Loss of material due to general, pitting, crevice corrosion	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5-1, 083	C
Steel components: all structural steel	Structural Support	Steel	Water - standing	Loss of material due to general, pitting, crevice corrosion	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5-1, 083	C

Table 3.5.2-4, Intake Pumping Station - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A6.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Water - flowing	Loss of material due to general, pitting, crevice corrosion	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5-1, 083	A
Structural bolting	Structural Support	Steel	Water - standing	Loss of material due to general, pitting, crevice corrosion	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5-1, 083	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A6.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A6.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A6.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A6.TP-261	3.5-1, 088	A

Table 3.5.2-4 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. Cracks, distortion, increase in component stress level due to settlement are not aging effects requiring management for structures founded on rock or bearing piles. See Subsection 3.5.2.2.2.1.3.
2. The interior slab is not weather exposed and not subject to loss of material or cracking due to freeze-thaw.

Table 3.5.2-5, Reinforced Concrete Chimney - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete (inaccessible areas): foundation	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A9.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Flood Barrier, Gaseous Release Path, Shelter and Protection, Shielding, Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A9.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Flood Barrier, Gaseous Release Path, Shelter and Protection, Shielding, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A9.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Flood Barrier, Gaseous Release Path, Shelter and Protection, Shielding, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A9.TP-204	3.5-1, 043	A

Table 3.5.2-5, Reinforced Concrete Chimney - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): all	Flood Barrier, Gaseous Release Path, Shelter and Protection, Shielding, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A9.TP-204	3.5-1, 043	A
Concrete: all	Flood Barrier, Gaseous Release Path, Shelter and Protection, Shielding, Structural Support	Concrete	Soil	None	None	III.A9.TP-30	3.5-1, 044	I, 1
Concrete (inaccessible areas): exterior above and below-grade; foundation	Flood Barrier, Gaseous Release Path, Shelter and Protection, Shielding, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A9.TP-67	3.5-1, 047	A
Concrete (accessible areas): all	Flood Barrier, Gaseous Release Path, Shelter and Protection, Shielding, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A9.TP-25	3.5-1, 054	A

Table 3.5.2-5, Reinforced Concrete Chimney - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): all	Flood Barrier, Gaseous Release Path, Shelter and Protection, Shielding, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A9.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior above and below-grade; foundation	Flood Barrier, Gaseous Release Path, Shelter and Protection, Shielding, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A9.TP-24	3.5-1, 063	A
Concrete (accessible areas): exterior above and below-grade; foundation	Flood Barrier, Gaseous Release Path, Shelter and Protection, Shielding, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A9.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): below-grade exterior; foundation	Flood Barrier, Gaseous Release Path, Shelter and Protection, Shielding, Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A9.TP-212	3.5-1, 065	A

Table 3.5.2-5, Reinforced Concrete Chimney - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): Interior	Gaseous Release Path, Shelter and Protection, Shielding, Structural Support	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A9.TP-26	3.5-1, 066	A
Concrete (accessible areas): above grade exterior	Flood Barrier, Gaseous Release Path, Shelter and Protection, Shielding, Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A9.TP-26	3.5-1, 066	A
Concrete: interior	Gaseous Release Path, Shelter and Protection, Shielding, Structural Support	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A9.TP-28	3.5-1, 067	A
Concrete: above grade exterior	Flood Barrier, Gaseous Release Path, Shelter and Protection, Shielding, Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A9.TP-28	3.5-1, 067	A

Table 3.5.2-5, Reinforced Concrete Chimney - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): below-grade exterior; foundation	Flood Barrier, Gaseous Release Path, Shelter and Protection, Shielding, Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A9.TP-29	3.5-1, 067	A
Masonry walls: all	Shelter and Protection, Shielding	Concrete block	Air - indoor uncontrolled	Cracking due to restraint shrinkage, creep, and aggressive environment	Masonry Walls (B.2.1.32)	III.A6.T-12	3.5-1, 070	A
Steel components: all structural steel	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Steel components: all structural steel	Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A9.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A9.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A9.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A9.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A9.TP-274	3.5-1, 082	A

Table 3.5.2-5, Reinforced Concrete Chimney - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A9.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A9.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A9.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A9.TP-261	3.5-1, 088	A

Table 3.5.2-5 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. Cracks, distortion, increase in component stress level due to settlement are not aging effects requiring management for structures founded on rock or bearing piles. See Subsection 3.5.2.2.2.1.3.

Table 3.5.2-6, Standby Gas Treatment Building - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete (inaccessible areas): foundation	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete: all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Soil	Cracking and distortion due to increased stress levels from settlement	Structures Monitoring (B.2.1.33)	III.A3.TP-30	3.5-1, 044	A

Table 3.5.2-6, Standby Gas Treatment Building - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): exterior above and below-grade; foundation	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Water-flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5-1, 047	A
Concrete (accessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior above and below-grade; foundation	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-24	3.5-1, 063	A
Concrete (accessible areas): exterior above and below-grade; foundation	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): below-grade exterior; foundation	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5-1, 065	A

Table 3.5.2-6, Standby Gas Treatment Building - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete (accessible areas): interior	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete (accessible areas): above grade exterior	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete: interior	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete: above grade exterior	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete (inaccessible areas): below-grade exterior; foundation	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5-1, 067	A

Table 3.5.2-6 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.5.2-7, Off Gas Treatment Building - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): foundation	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Fission Product Barrier, Flood Barrier, Shielding, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Fission Product Barrier, Flood Barrier, Shielding, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Fission Product Barrier, Flood Barrier, Shielding, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A

Table 3.5.2-7, Off Gas Treatment Building - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): all	Fission Product Barrier, Flood Barrier, Shielding, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete: all	Fission Product Barrier, Flood Barrier, Shielding, Shelter and Protection, Structural Support	Concrete	Soil	None	None	III.A3.TP-30	3.5-1, 044	I, 1
Concrete (inaccessible areas): exterior above and below-grade; foundation	Fission Product Barrier, Flood Barrier, Shielding, Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5-1, 047	A
Concrete (accessible areas): all	Fission Product Barrier, Flood Barrier, Shielding, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A

Table 3.5.2-7, Off Gas Treatment Building - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): all	Fission Product Barrier, Flood Barrier, Shielding, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior above and below-grade; foundation	Fission Product Barrier, Flood Barrier, Shielding, Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-24	3.5-1, 063	A
Concrete (accessible areas): exterior above and below-grade; foundation	Fission Product Barrier, Flood Barrier, Shielding, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): below-grade exterior; foundation	Fission Product Barrier, Flood Barrier, Shielding, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5-1, 065	A

Table 3.5.2-7, Off Gas Treatment Building - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): interior	Fission Product Barrier, Flood Barrier, Shielding, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete (accessible areas): above grade exterior	Fission Product Barrier, Flood Barrier, Shielding, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete: interior	Fission Product Barrier, Flood Barrier, Shielding, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete: above grade exterior	Fission Product Barrier, Flood Barrier, Shielding, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A

Table 3.5.2-7, Off Gas Treatment Building - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): below-grade exterior; foundation	Fission Product Barrier, Flood Barrier, Shielding, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5-1, 067	A
Masonry Walls: all	Shielding	Concrete block	Air - indoor uncontrolled	Cracking due to restraint shrinkage, creep, and aggressive environment	Masonry Walls (B.2.1.32)	III.A3.T-12	3.5-1, 070	A

Table 3.5.2-7 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. Cracks, distortion, increase in component stress level due to settlement are not aging effects requiring management for structures founded on rock or bearing piles. See Subsection 3.5.2.2.2.1.3.

Table 3.5.2-8, Equipment Access Lock - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): foundation	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A2.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Pressure Boundary, Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A2.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Pressure Boundary, Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A2.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Pressure Boundary, Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A2.TP-204	3.5-1, 043	A

Table 3.5.2-8, Equipment Access Lock - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): all	Pressure Boundary, Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A2.TP-204	3.5-1, 043	A
Concrete: all	Pressure Boundary, Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Soil	None	None	III.A2.TP-30	3.5-1, 044	I, 1
Concrete (inaccessible areas): exterior above and below-grade; foundation	Pressure Boundary, Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A2.TP-67	3.5-1, 047	A
Concrete (accessible areas): all	Pressure Boundary, Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A2.TP-25	3.5-1, 054	A

Table 3.5.2-8, Equipment Access Lock - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): all	Pressure Boundary, Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A2.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior above and below-grade; foundation	Pressure Boundary, Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A2.TP-24	3.5-1, 063	A
Concrete (accessible areas): exterior above and below-grade; foundation	Pressure Boundary, Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A2.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): below-grade exterior; foundation	Pressure Boundary, Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A2.TP-212	3.5-1, 065	A

Table 3.5.2-8, Equipment Access Lock - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): interior	Pressure Boundary, Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A2.TP-26	3.5-1, 066	A
Concrete (accessible areas): above grade exterior	Pressure Boundary, Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A2.TP-26	3.5-1, 066	A
Concrete: interior	Pressure Boundary, Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A2.TP-28	3.5-1, 067	A
Concrete: above grade exterior	Pressure Boundary, Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A2.TP-28	3.5-1, 067	A

Table 3.5.2-8, Equipment Access Lock - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): below-grade exterior; foundation	Pressure Boundary, Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A2.TP-29	3.5-1, 067	A
Steel components: all structural steel	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A2.TP-302	3.5-1, 077	A
Steel components: all structural steel	Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A2.TP-302	3.5-1, 077	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A2.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A2.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A2.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A2.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A

Table 3.5.2-8, Equipment Access Lock - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A2.TP-261	3.5-1, 088	A

<u>Table 3.5.2-8 Notes</u>

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. Cracks, distortion, increase in component stress level due to settlement are not aging effects requiring management for structures founded on rock or bearing piles. See Subsection 3.5.2.2.2.1.3.

Table 3.5.2-9, Vacuum Pipe Building - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): foundation	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete: all	Shelter and Protection, Structural Support	Concrete	Soil	Cracking and distortion due to increased stress levels from settlement	Structures Monitoring (B.2.1.33)	III.A3.TP-30	3.5-1, 044	A
Concrete (inaccessible areas): exterior below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5-1, 047	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A

Table 3.5.2-9, Vacuum Pipe Building - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-24	3.5-1, 063	A
Concrete (accessible areas): exterior below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5-1, 065	A
Concrete (accessible areas): interior	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete: interior	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A

Table 3.5.2-9, Vacuum Pipe Building - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5-1, 067	A

Table 3.5.2-9 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.5.2-10, Turbine Buildings - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete (inaccessible areas): foundation	Shelter and Protection, Shielding, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Shelter and Protection, Shielding, Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Shelter and Protection, Shielding, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Shielding, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Shielding, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete: all	Shelter and Protection, Shielding, Structural Support	Concrete	Soil	None	None	III.A3.TP-30	3.5-1, 044	I, 1

Table 3.5.2-10, Turbine Buildings - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): exterior above and below-grade; foundation	Shelter and Protection, Shielding, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5-1, 047	A
Concrete (accessible areas): all	Shelter and Protection, Shielding, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Shelter and Protection, Shielding, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Shielding, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-24	3.5-1, 063	A
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Shielding, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Shielding, Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5-1, 065	A

Table 3.5.2-10, Turbine Buildings - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): interior	Shelter and Protection, Shielding, Structural Support	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete (accessible areas): above grade exterior	Shelter and Protection, Shielding, Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete: interior	Shelter and Protection, Shielding, Structural Support	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete: above grade exterior	Shelter and Protection, Shielding, Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Shielding, Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5-1, 067	A
Masonry walls: all (Unit 2 only)	Structural Support	Concrete block	Air - indoor uncontrolled	Cracking due to restraint shrinkage, creep, and aggressive environment	Masonry Walls (B.2.1.32)	III.A3.T-12	3.5-1, 070	A

Table 3.5.2-10, Turbine Buildings - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A

<u>Table 3.5.2-10 Notes</u>

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. Cracks, distortion, increase in component stress level due to settlement are not aging effects requiring management for structures founded on rock or bearing piles. See Subsection 3.5.2.2.2.1.3.

Table 3.5.2-11, Radwaste Building - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): foundation	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete: all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Soil	None	None	III.A3.TP-30	3.5-1, 044	I, 1

Table 3.5.2-11, Radwaste Building - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete (inaccessible areas): exterior above and below-grade; foundation	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5-1, 047	A
Concrete (accessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior above and below-grade; foundation	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-24	3.5-1, 063	A
Concrete (accessible areas): exterior above and below-grade; foundation	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): below-grade exterior; foundation	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5-1, 065	A

Table 3.5.2-11, Radwaste Building - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): interior	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete (accessible areas): above grade exterior	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete: interior	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete: above grade exterior	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete (inaccessible areas): below-grade exterior; foundation	Flood Barrier, Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5-1, 067	A
Hatch	Shelter and Protection, Structural Support	Aluminum	Air	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5-1, 100	C

Table 3.5.2-11, Radwaste Building - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Hatch	Shelter and Protection, Structural Support	Aluminum	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5-1, 100	C
Masonry walls: all	Structural Support	Concrete block	Air - indoor uncontrolled	Cracking due to restraint shrinkage, creep, and aggressive environment	Masonry Walls (B.2.1.32)	III.A3.T-12	3.5-1, 070	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Galvanized steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A

Table 3.5.2-11, Radwaste Building - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A

Table 3.5.2-11 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. Cracks, distortion, increase in component stress level due to settlement are not aging effects requiring management for structures founded on rock or bearing piles. See Subsection 3.5.2.2.2.1.3.

Table 3.5.2-12, Service Building - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete: all	Shelter and Protection, Structural Support	Concrete	Soil	Cracking and distortion due to increased stress levels from settlement	Structures Monitoring (B.2.1.33)	III.A3.TP-30	3.5-1, 044	A
Concrete (inaccessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5-1, 047	A

Table 3.5.2-12, Service Building - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-24	3.5-1, 063	A
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5-1, 065	A
Concrete (accessible areas): interior	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete (accessible areas): above grade exterior	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A

Table 3.5.2-12, Service Building - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: interior	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete: above grade exterior	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5-1, 067	A
Masonry Walls: all	Structural Support	Concrete Block	Air - indoor uncontrolled	Cracks due to restraint, shrinkage, creep, aggressive environment	Masonry Walls (B.2.1.32)	III.A3.T-12	3.5-1, 070	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5-1, 080	A

Table 3.5.2-12, Service Building - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Galvanized steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A

Table 3.5.2-12 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.5.2-13, Vent Vaults - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete: all	Shelter and Protection, Structural Support	Concrete	Soil	Cracking and distortion due to increased stress levels from settlement	Structures Monitoring (B.2.1.33)	III.A3.TP-30	3.5-1, 044	A
Concrete (inaccessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5-1, 047	A

Table 3.5.2-13, Vent Vaults - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-24	3.5-1, 063	A
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5-1, 065	A
Concrete (accessible areas): interior	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete (accessible areas): above grade exterior	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A

Table 3.5.2-13, Vent Vaults - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: interior	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete: above grade exterior	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5-1, 067	A

Table 3.5.2-13 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.5.2-14, Gate Structure No. 2 - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete: all	Shelter and Protection, Structural Support, Water Retaining Boundary	Concrete	Soil	None	None	III.A6.TP-30	3.5-1, 044	I, 1
Concrete (inaccessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support, Water Retaining Boundary	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A6.TP-110	3.5-1, 049	A
Concrete (inaccessible areas): exterior below-grade; foundation	Shelter and Protection, Structural Support, Water Retaining Boundary	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A6.TP-110	3.5-1, 049	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support, Water Retaining Boundary	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-220	3.5-1, 050	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support, Water Retaining Boundary	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-220	3.5-1, 050	A

Table 3.5.2-14, Gate Structure No. 2 - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support, Water Retaining Boundary	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-220	3.5-1, 050	A
Concrete (inaccessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support, Water Retaining Boundary	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A6.TP-109	3.5-1, 051	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support, Water Retaining Boundary	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support, Water Retaining Boundary	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support, Water Retaining Boundary	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-38	3.5-1, 059	A

Table 3.5.2-14, Gate Structure No. 2 - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): all	Shelter and Protection, Structural Support, Water Retaining Boundary	Concrete	Water - flowing	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-38	3.5-1, 059	A
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support, Water Retaining Boundary	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-36	3.5-1, 060	A
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support, Water Retaining Boundary	Concrete	Water - flowing	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-36	3.5-1, 060	A
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support, Water Retaining Boundary	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-37	3.5-1, 061	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support, Water Retaining Boundary	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A6.TP-104	3.5-1, 065	A

Table 3.5.2-14, Gate Structure No. 2 - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support, Water Retaining Boundary	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A6.TP-104	3.5-1, 065	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support, Water Retaining Boundary	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	C
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support, Water Retaining Boundary	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A6.TP-107	3.5-1, 067	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support, Water Retaining Boundary	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-34	3.5-1, 096	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support, Water Retaining Boundary	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-34	3.5-1, 096	A
Steel components: all structural steel	Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Steel components: all structural steel	Structural Support	Steel	Water - flowing	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	G, 2

Table 3.5.2-14 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. Cracks, distortion, increase in component stress level due to settlement are not aging effects requiring management for structures founded on rock or bearing piles. See Subsection 3.5.2.2.2.1.3.
2. The Gate Structure No. 2 steel is exposed to water and is potentially subject to loss of material. The Structures Monitoring program (B.2.1.33) will manage the aging of this material / environment combination.

Table 3.5.2-15, Gate Structure No. 3 - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete: all	Structural Support	Concrete	Soil	None	None	III.A6.TP-30	3.5-1, 044	I, 1
Concrete (inaccessible areas): exterior above and below-grade; foundation	Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A6.TP-110	3.5-1, 049	A
Concrete (inaccessible areas): exterior below-grade; foundation	Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A6.TP-110	3.5-1, 049	A
Concrete (inaccessible areas): all	Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-220	3.5-1, 050	A
Concrete (inaccessible areas): all	Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-220	3.5-1, 050	A
Concrete (inaccessible areas): all	Structural Support	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-220	3.5-1, 050	A
Concrete (inaccessible areas): exterior above and below-grade; foundation	Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A6.TP-109	3.5-1, 051	A
Concrete (accessible areas): all	Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Structural Support	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-25	3.5-1, 054	A

Table 3.5.2-15, Gate Structure No. 3 - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: exterior above and below-grade; foundation	Structural Support	Concrete	Water - flowing	Loss of material due to abrasion; cavitation	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-20	3.5-1, 056	A
Concrete (accessible areas): all	Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-38	3.5-1, 059	A
Concrete (accessible areas): all	Structural Support	Concrete	Water - flowing	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-38	3.5-1, 059	A
Concrete (accessible areas): exterior above and below-grade; foundation	Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-36	3.5-1, 060	A
Concrete (accessible areas): exterior above and below-grade; foundation	Structural Support	Concrete	Water - flowing	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-36	3.5-1, 060	A
Concrete (accessible areas): exterior above and below-grade; foundation	Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-37	3.5-1, 061	A
Concrete (inaccessible areas): all	Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A6.TP-104	3.5-1, 065	A

Table 3.5.2-15, Gate Structure No. 3 - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): all	Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A6.TP-104	3.5-1, 065	A
Concrete (accessible areas): all	Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	C
Concrete (inaccessible areas): all	Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A6.TP-107	3.5-1, 067	A
Concrete (accessible areas): all	Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-34	3.5-1, 096	A
Concrete (accessible areas): all	Structural Support	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-34	3.5-1, 096	A
Steel components: all structural steel	Structural Support	Steel	Concrete	None	None	V.F.EP-112	3.2-1, 055	C
Steel components: all structural steel	Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	C
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A6.TP-248	3.5-1, 080	A

Table 3.5.2-15, Gate Structure No. 3 - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5-1, 083	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A6.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Concrete	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A6.TP-261	3.5-1, 088	A

<u>Table 3.5.2-15 Notes</u>

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. Cracks, distortion, increase in component stress level due to settlement are not aging effects requiring management for structures founded on rock or bearing piles. See Subsection 3.5.2.2.2.1.3.

Table 3.5.2-16, Discharge Control Structure - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: all	Shelter and Protection, Structural Support	Concrete	Soil	None	None	III.A6.TP-30	3.5-1, 044	I, 1
Concrete (inaccessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A6.TP-110	3.5-1, 049	A
Concrete (inaccessible areas): exterior below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A6.TP-110	3.5-1, 049	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-220	3.5-1, 050	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-220	3.5-1, 050	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Water-Flowing	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-220	3.5-1, 050	A
Concrete (inaccessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A6.TP-109	3.5-1, 051	A

Table 3.5.2-16, Discharge Control Structure - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-25	3.5-1, 054	A
Concrete: exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Loss of material due to abrasion; cavitation	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-20	3.5-1, 056	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-38	3.5-1, 059	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Water - flowing	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-38	3.5-1, 059	A
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-36	3.5-1, 060	A
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-36	3.5-1, 060	A

Table 3.5.2-16, Discharge Control Structure - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-37	3.5-1, 061	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A6.TP-104	3.5-1, 065	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A6.TP-104	3.5-1, 065	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	C
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A6.TP-107	3.5-1, 067	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-34	3.5-1, 096	A

Table 3.5.2-16, Discharge Control Structure - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-34	3.5-1, 096	A

Table 3.5.2-16 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. Cracks, distortion, increase in component stress level due to settlement are not aging effects requiring management for structures founded on rock or bearing piles. See Subsection 3.5.2.2.2.1.3.

Table 3.5.2-17, Circulating Water Conduits - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: all	Structural Support, Water Retaining Boundary	Concrete	Soil	Cracking and distortion due to increased stress levels from settlement	Structures Monitoring (B.2.1.33)	III.A6.TP-30	3.5-1, 044	A
Concrete (inaccessible areas): all	Structural Support, Water Retaining Boundary	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-220	3.5-1, 050	A
Concrete (inaccessible areas): all	Structural Support, Water Retaining Boundary	Concrete	Soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-220	3.5-1, 050	A
Concrete (inaccessible areas): all	Structural Support, Water Retaining Boundary	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-220	3.5-1, 050	A
Concrete (inaccessible areas): exterior below-grade; foundation; interior slab	Structural Support, Water Retaining Boundary	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A6.TP-109	3.5-1, 051	A
Concrete (accessible areas): all	Structural Support, Water Retaining Boundary	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A6.TP-25	3.5-1, 054	A
Concrete: foundation; interior slab	Structural Support, Water Retaining Boundary	Concrete	Water - flowing	Loss of material due to abrasion; cavitation	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-20	3.5-1, 056	A

Table 3.5.2-17, Circulating Water Conduits - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete (accessible areas): all	Structural Support, Water Retaining Boundary	Concrete	Water - flowing	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-38	3.5-1, 059	A
Concrete (inaccessible areas): all	Structural Support, Water Retaining Boundary	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A6.TP-104	3.5-1, 065	A
Concrete (inaccessible areas): all	Structural Support, Water Retaining Boundary	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A6.TP-107	3.5-1, 067	A
Concrete (accessible areas): all	Structural Support, Water Retaining Boundary	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-34	3.5-1, 096	A
Steel components: all structural steel	Structural Support	Steel	Water- flowing	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	G, 1

Table 3.5.2-17 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. The circulating water conduits steel is exposed to water and is potentially subject to loss of material. The Structures Monitoring program (B.2.1.33) will manage the aging of this material / environment combination.

Table 3.5.2-18, Diesel High Pressure Fire Pump House - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete (inaccessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5-1, 047	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-24	3.5-1, 063	A
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5-1, 064	A
Concrete (accessible areas): interior	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete (accessible areas): above grade exterior	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A

Table 3.5.2-18, Diesel High Pressure Fire Pump House - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete: interior	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete: above grade exterior	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Raw or Treated Water	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	G, 1
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A

Table 3.5.2-18, Diesel High Pressure Fire Pump House - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Raw or Treated Water	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Raw or Treated Water	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A

Table 3.5.2-18 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. The Diesel High Pressure Pump House steel is exposed to water and is potentially subject to loss of material. The Structures Monitoring program (B.2.1.33) will manage the aging of this material / environment combination.

Table 3.5.2-19, Low Level Radwaste (LLRW) Storage Facility - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): foundation	Flood Barrier, Missile Barrier, Shielding	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Flood Barrier, Missile Barrier, Shielding	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Flood Barrier, Missile Barrier, Shielding	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Flood Barrier, Missile Barrier, Shielding	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Flood Barrier, Missile Barrier, Shielding	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Flood Barrier, Missile Barrier, Shielding	Concrete	Soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Flood Barrier, Missile Barrier, Shielding	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete: all	Flood Barrier, Missile Barrier, Shielding	Concrete	Soil	Cracking and distortion due to increased stress levels from settlement	Structures Monitoring (B.2.1.33)	III.A3.TP-30	3.5-1, 044	A
Concrete (inaccessible areas): exterior above and below-grade; foundation	Flood Barrier, Missile Barrier, Shielding	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5-1, 047	A

Table 3.5.2-19, Low Level Radwaste (LLRW) Storage Facility - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete (accessible areas): all	Flood Barrier, Missile Barrier, Shielding	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Flood Barrier, Missile Barrier, Shielding	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Flood Barrier, Missile Barrier, Shielding	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Flood Barrier, Missile Barrier, Shielding	Concrete	Soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Flood Barrier, Missile Barrier, Shielding	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior above and below-grade; foundation	Flood Barrier, Missile Barrier, Shielding	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-24	3.5-1, 063	A
Concrete (accessible areas): exterior above and below-grade; foundation	Flood Barrier, Missile Barrier, Shielding	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): below-grade exterior; foundation	Flood Barrier, Missile Barrier, Shielding	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5-1, 065	A

Table 3.5.2-19, Low Level Radwaste (LLRW) Storage Facility - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete (accessible areas): interior	Flood Barrier, Missile Barrier, Shielding	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete (accessible areas): above grade exterior	Flood Barrier, Missile Barrier, Shielding	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete: interior	Flood Barrier, Missile Barrier, Shielding	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete: above grade exterior	Flood Barrier, Missile Barrier, Shielding	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete (inaccessible areas): below-grade exterior; foundation	Flood Barrier, Missile Barrier, Shielding	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5-1, 067	A
Steel components: all structural steel	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Steel components: all structural steel	Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A

Table 3.5.2-19, Low Level Radwaste (LLRW) Storage Facility - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A

Table 3.5.2-19 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.5.2-20, Transformer Yard - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): exterior above and below-grade; foundation	Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Structural Support	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete: all	Structural Support	Concrete	Soil	Cracking and distortion due to increased stress levels from settlement	Structures Monitoring (B.2.1.33)	III.A3.TP-30	3.5-1, 044	A
Concrete (inaccessible areas): exterior above and below-grade; foundation	Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5-1, 047	A
Concrete (accessible areas): all	Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A

Table 3.5.2-20, Transformer Yard - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): all	Structural Support	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior above and below-grade; foundation	Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-24	3.5-1, 063	A
Concrete (accessible areas): exterior above and below-grade; foundation	Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): below-grade exterior; foundation	Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5-1, 065	A
Concrete (accessible areas): above grade exterior	Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete: above grade exterior	Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete (inaccessible areas): below-grade exterior; foundation	Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5-1, 067	A

Table 3.5.2-20, Transformer Yard - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Steel components: all structural steel	Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A

Table 3.5.2-20 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.

B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.

C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.

D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.

F. Material not in NUREG-2191 for this component.

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.

Plant Specific Notes

None.

Table 3.5.2-21, 161 kV Switchyard - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete: all	Shelter and Protection, Structural Support	Concrete	Soil	Cracking and distortion due to increased stress levels from settlement	Structures Monitoring (B.2.1.33)	III.A3.TP-30	3.5-1, 044	A
Concrete (inaccessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5-1, 047	A

Table 3.5.2-21, 161 kV Switchyard - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5-1, 065	A
Concrete (accessible areas): interior	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete (accessible areas): above grade exterior	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete: interior	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A

Table 3.5.2-21, 161 kV Switchyard - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete: above grade exterior	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5-1, 067	A
Steel components: all structural steel	Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A

<u>Table 3.5.2-21 Notes</u>

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.5.2-22, 500 kV Switchyard - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete: all	Shelter and Protection, Structural Support	Concrete	Soil	Cracking and distortion due to increased stress levels from settlement	Structures Monitoring (B.2.1.33)	III.A3.TP-30	3.5-1, 044	A
Concrete (inaccessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5-1, 047	A

Table 3.5.2-22, 500 kV Switchyard - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5-1, 065	A
Concrete (accessible areas): interior	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete (accessible areas): above grade exterior	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete: interior	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A

Table 3.5.2-22, 500 kV Switchyard - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete: above grade exterior	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5-1, 067	A
Steel components: all structural steel	Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A

Table 3.5.2-22 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.5.2-23, Condensate Water Storage Tanks Foundations, Trenches, and Tunnels - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): foundation	Flood Barrier, Missile Barrier, Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A8.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A8.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A8.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A8.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A8.TP-204	3.5-1, 043	A
Concrete: all	Shelter and Protection, Structural Support	Concrete	Soil	Cracking and distortion due to increased stress levels from settlement	Structures Monitoring (B.2.1.33)	III.A8.TP-30	3.5-1, 044	A
Concrete (inaccessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A8.TP-67	3.5-1, 047	A

Table 3.5.2-23, Condensate Water Storage Tanks Foundations, Trenches, and Tunnels - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A8.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A8.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A8.TP-24	3.5-1, 063	A
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A8.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A8.TP-212	3.5-1, 065	A
Concrete: above grade exterior	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A

Table 3.5.2-23, Condensate Water Storage Tanks Foundations, Trenches, and Tunnels - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A8.TP-29	3.5-1, 067	A
Earthfill (rock and sand)	Structural Support	Earthfill (rock and sand)	Air - outdoor, Groundwater/ soil, water-flowing, water-standing	None	None	N/A	N/A	J, 1
Steel components: all structural steel	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A8.TP-302	3.5-1, 077	A
Steel components: all structural steel	Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A8.TP-302	3.5-1, 077	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A8.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel; galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A8.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A8.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A8.TP-261	3.5-1, 088	A

Table 3.5.2-23 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. The earthen materials of the Condensate Water Storage Tanks foundation interior base are protected from aging effects by the concrete perimeter ring and Condensate Water Storage Tank bottom.

Table 3.5.2-24, Nitrogen Storage Tank Foundation - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): foundation	Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A8.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A8.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A8.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A8.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Structural Support	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A8.TP-204	3.5-1, 043	A
Concrete: all	Structural Support	Concrete	Soil	Cracking and distortion due to increased stress levels from settlement	Structures Monitoring (B.2.1.33)	III.A8.TP-30	3.5-1, 044	A
Concrete (inaccessible areas): exterior above and below-grade; foundation	Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A8.TP-67	3.5-1, 047	A
Concrete (accessible areas): all	Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A8.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A8.TP-25	3.5-1, 054	A

Table 3.5.2-24, Nitrogen Storage Tank Foundation - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete (accessible areas): all	Structural Support	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A8.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior above and below-grade; foundation	Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A8.TP-24	3.5-1, 063	A
Concrete (accessible areas): exterior above and below-grade; foundation	Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A8.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): below-grade exterior; foundation	Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A8.TP-212	3.5-1, 065	A
Concrete: above grade exterior	Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete (inaccessible areas): below-grade exterior; foundation	Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A8.TP-29	3.5-1, 067	A

<u>Table 3.5.2-24 Notes</u>

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.5.2-25, Supplemental Diesel Generator Building - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete: all	Shelter and Protection, Structural Support	Concrete	Soil	Cracking and distortion due to increased stress levels from settlement	Structures Monitoring (B.2.1.33)	III.A3.TP-30	3.5-1, 044	A

Table 3.5.2-25, Supplemental Diesel Generator Building - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete (inaccessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5-1, 047	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-24	3.5-1, 063	A
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5-1, 064	A

Table 3.5.2-25, Supplemental Diesel Generator Building - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5-1, 065	A
Concrete (accessible areas): interior	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete (accessible areas): above grade exterior	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete: interior	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete: above grade exterior	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5-1, 067	A

Table 3.5.2-25, Supplemental Diesel Generator Building - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A

<u>Table 3.5.2-25 Notes</u>

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.

B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.

C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.

D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.

F. Material not in NUREG-2191 for this component.

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.

Plant Specific Notes

None.

Table 3.5.2-26, Containment Atmosphere Dilution System Storage Tank Foundations - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): foundation	Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A8.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A8.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A8.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A8.TP-204	3.5-1, 043	A
Concrete: all	Structural Support	Concrete	Soil	Cracking and distortion due to increased stress levels from settlement	Structures Monitoring (B.2.1.33)	III.A8.TP-30	3.5-1, 044	A
Concrete (inaccessible areas): exterior above and below-grade; foundation	Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A8.TP-67	3.5-1, 047	A
Concrete (accessible areas): all	Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A8.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior above and below-grade; foundation	Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A8.TP-24	3.5-1, 063	A

Table 3.5.2-26, Containment Atmosphere Dilution System Storage Tank Foundations - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): exterior above and below-grade; foundation	Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A8.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): below-grade exterior; foundation	Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A8.TP-212	3.5-1, 065	A
Concrete: above grade exterior	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete (inaccessible areas): below-grade exterior; foundation	Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A8.TP-29	3.5-1, 067	A

<u>Table 3.5.2-26 Notes</u>

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.5.2-27, Intake Channel - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Earthen water-control structures: dams; embankments; channels; canals	Structural Support	Earthfill (clay and in-situ soil)	Air - outdoor	Loss of material; loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-22	3.5-1, 058	A
Earthen water-control structures: dams; embankments; channels; canals	Structural Support	Earthfill (clay and in-situ soil)	Soil	Loss of material; loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-22	3.5-1, 058	G, 1
Earthen water-control structures: dams; embankments; channels; canals	Structural Support	Earthfill (clay and in-situ soil)	Water - flowing	Loss of material; loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-22	3.5-1, 058	A
Earthen water-control structures: dams; embankments; channels; canals	Structural Support	Earthfill (clay and in-situ soil)	Water - standing	Loss of material; loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-22	3.5-1, 058	A

Table 3.5.2-27 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. The inspection of Water-Control Structures associated with Nuclear Power Plants program (B.2.1.34) will manage the potential aging effect (loss of form) associated with an environment of soil for the Intake Channel.

Table 3.5.2-28, North Bank of Cool Water Channel East of Gate Structure No. 2 - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Earthen water-control structures: embankments;	Structural Support	Earthfill (clay and in-situ soil)	Air - outdoor	Loss of material; loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-22	3.5-1, 058	A
Earthen water-control structures: embankments;	Structural Support	Earthfill (clay and in-situ soil)	Soil	Loss of material; loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-22	3.5-1, 058	G, 1
Earthen water-control structures: embankments	Structural Support	Earthfill (clay and in-situ soil)	Water - flowing	Loss of material; loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-22	3.5-1, 058	A
Earthen water-control structures: embankments	Structural Support	Earthfill (clay and in-situ soil)	Water - standing	Loss of material; loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-22	3.5-1, 058	A

Table 3.5.2-28 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. The inspection of Water-Control Structures associated with Nuclear Power Plants program (B.2.1.34) will manage the potential aging effect (loss of form) associated with an environment of soil for the North Bank of Cool Water Channel East of Gate Structure No. 2.

Table 3.5.2-29, South Dike of Cool Water Channel between Gate Structures No. 2 and No.3 - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Earthen water-control structures: dams	Structural Support	Earthfill (clay and in-situ soil)	Air - outdoor	Loss of material; loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-22	3.5-1, 058	A
Earthen water-control structures: dams	Structural Support	Earthfill (clay and in-situ soil)	Soil	Loss of material; loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-22	3.5-1, 058	G, 1
Earthen water-control structures: dams	Structural Support	Earthfill (clay and in-situ soil)	Water - flowing	Loss of material; loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-22	3.5-1, 058	A
Earthen water-control structures: dams	Structural Support	Earthfill (clay and in-situ soil)	Water - standing	Loss of material; loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.T-22	3.5-1, 058	A

Table 3.5.2-29 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. The inspection of Water-Control Structures associated with Nuclear Power Plants program (B.2.1.34) will manage the potential aging effect (loss of form) associated with an environment of soil for the South Dike of Cool Water Channel between Gate Structure No. 2 and No. 3.

Table 3.5.2-30, Earth Berm - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Rock and Earthfill Embankment	Structural Support	Rock and Earthfill	Air - outdoor	Loss of material; loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	Structures Monitoring (B.2.1.33)	None	None	J, 1
Rock and Earthfill Embankment	Structural Support	Rock and Earthfill	Groundwater / soil	Loss of material; loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	Structures Monitoring (B.2.1.33)	None	None	J, 1

Table 3.5.2-30 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. The Structures Monitoring Program (B.2.1.33) will manage the potential loss of material and loss of form that could occur with the BFN Earth Berm when exposed to air-outdoor or groundwater/soil.

Table 3.5.2-31, Residual Heat Removal Service Water Tunnel - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete: all	Shelter and Protection, Structural Support	Concrete	Soil	None	None	III.A3.TP-30	3.5-1, 044	I, 1
Concrete (inaccessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5-1, 047	A

Table 3.5.2-31, Residual Heat Removal Service Water Tunnel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-24	3.5-1, 063	A
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5-1, 065	A
Concrete (accessible areas): interior	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete (accessible areas): above grade exterior	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A

Table 3.5.2-31, Residual Heat Removal Service Water Tunnel - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: interior	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete: above grade exterior	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5-1, 067	A
Steel components: all structural steel	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Steel components: all structural steel	Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Steel components: all structural steel	Structural Support	Steel	Groundwater / soil	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	G, 2
Structural Bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5-1, 080	A
Structural Bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5-1, 080	A

Table 3.5.2-31, Residual Heat Removal Service Water Tunnel - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Structural Bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A
Structural Bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A
Structural Bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural Bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural Bolting	Structural Support	Galvanized Steel	Groundwater / soil	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural Bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural Bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural Bolting	Structural Support	Steel	Groundwater / soil	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A

Table 3.5.2-31 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. Cracks, distortion, increase in component stress level due to settlement are not aging effects requiring management for structures founded on rock or bearing piles. See Subsection 3.5.2.2.2.1.3.
2. Steel with a buried environment that includes groundwater/soil is conducive to the potential for loss of material due to corrosion. The Structures Monitoring program (B.2.1.33) will be used to manage this aging effect.

Table 3.5.2-32, Electrical Cable Tunnel (from Intake Pumping Station to Powerhouse) - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete: all	Shelter and Protection, Structural Support	Concrete	Soil	Cracking and distortion due to increased stress levels from settlement	Structures Monitoring (B.2.1.33)	III.A3.TP-30	3.5-1, 044	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5-1, 047	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5-1, 065	A
Concrete (accessible areas): interior	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A

Table 3.5.2-32, Electrical Cable Tunnel (from Intake Pumping Station to Powerhouse) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: interior	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5-1, 067	A

Table 3.5.2-32 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.5.2-33, Underground Concrete Encased Structures - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete: all	Shelter and Protection, Structural Support	Concrete	Soil	Cracking and distortion due to increased stress levels from settlement	Structures Monitoring (B.2.1.33)	III.A3.TP-30	3.5-1, 044	A
Concrete (inaccessible areas): exterior below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5-1, 047	A

Table 3.5.2-33, Underground Concrete Encased Structures - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-24	3.5-1, 063	A
Concrete (accessible areas): exterior below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5-1, 065	A
Concrete (accessible areas): interior	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete: interior	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A

Table 3.5.2-33, Underground Concrete Encased Structures - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5-1, 067	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Concrete	None	None	V.F.EP-112	3.2-1, 055	C

<u>Table 3.5.2-33 Notes</u>

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.5.2-34, Yard Structures, General - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete: all	Shelter and Protection, Structural Support	Concrete	Soil	Cracking and distortion due to increased stress levels from settlement	Structures Monitoring (B.2.1.33)	III.A3.TP-30	3.5-1, 044	A
Concrete (inaccessible areas): exterior above grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5-1, 047	A

Table 3.5.2-34, Yard Structures, General - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior above grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-24	3.5-1, 063	A
Concrete (accessible areas): exterior above grade; foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5-1, 065	A
Concrete (accessible areas): above grade exterior	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A

Table 3.5.2-34, Yard Structures, General - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete: above grade exterior	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5-1, 067	A

Table 3.5.2-34 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.5.2-35, South Access Retaining Wall - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete: all	Shelter and Protection, Structural Support	Concrete	Soil	Cracking and distortion due to increased stress levels from settlement	Structures Monitoring (B.2.1.33)	III.A3.TP-30	3.5-1, 044	A
Concrete (inaccessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5-1, 047	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A

Table 3.5.2-35, South Access Retaining Wall - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-24	3.5-1, 063	A
Concrete (accessible areas): exterior above and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5-1, 065	A
Concrete (accessible areas): above grade exterior	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete: above grade exterior	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater / soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5-1, 067	A

<u>Table 3.5.2-35 Notes</u>

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

Table 3.5.2-36, Structural Commodities (Cable Trays and Supports) - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - indoor uncontrolled	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B2.TP-42	3.5-1, 055	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - outdoor	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B2.TP-42	3.5-1, 055	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A

Table 3.5.2-36, Structural Commodities (Cable Trays and Supports) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-6	3.5-1, 093	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-43	3.5-1, 092	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-43	3.5-1, 092	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Galvanized steel	Air - indoor uncontrolled	None	None	III.B2.TP-8	3.5-1, 095	A

Table 3.5.2-36, Structural Commodities (Conduit and Conduit Supports) - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - indoor uncontrolled	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B2.TP-42	3.5-1, 055	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - outdoor	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B2.TP-42	3.5-1, 055	A
Conduit	Structural Support, Shelter and Protection	Steel	Concrete	None	None	V.F.EP-112	3.2-1, 055	C
Conduit	Structural Support, Shelter and Protection	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-43	3.5-1, 092	C
Conduit	Structural Support, Shelter and Protection	Steel	Air - outdoor	Loss of material due to general, pitting corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-43	3.5-1, 092	C
Conduit	Structural Support, Shelter and Protection	Aluminum	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	C

Table 3.5.2-36, Structural Commodities (Conduit and Conduit Supports) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Conduit	Structural Support, Shelter and Protection	Aluminum	Air - outdoor	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	A
Conduit	Structural Support, Shelter and Protection	Aluminum	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	A
Conduit	Structural Support, Shelter and Protection	Stainless Steel	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Concrete	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A

Table 3.5.2-36, Structural Commodities (Conduit and Conduit Supports) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Concrete	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Support members; welds; bolted connections; support anchorage to building structure	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel	Concrete	None	None	V.F.EP-112	3.2-1, 055	C
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-43	3.5-1, 092	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-43	3.5-1, 092	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-6	3.5-1, 093	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Galvanized steel	Air - indoor uncontrolled	None	None	III.B2.TP-8	3.5-1, 095	A

Table 3.5.2-36, Structural Commodities (Conduit and Conduit Supports) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	A

Table 3.5.2-36, Structural Commodities (Electrical Panels, Racks, Cabinets, and Other Enclosures) - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - indoor uncontrolled	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B3.TP-42	3.5-1, 055	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - outdoor	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B3.TP-42	3.5-1, 055	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Groundwater / soil	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B3.TP-42	3.5-1, 055	G, 1
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B3.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B3.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B3.TP-274	3.5-1, 082	A

Table 3.5.2-36, Structural Commodities (Electrical Panels, Racks, Cabinets, and Other Enclosures) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B3.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B3.TP-261	3.5-1, 088	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting corrosion	Structures Monitoring (B.2.1.33)	III.B3.TP-43	3.5-1, 092	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B3.TP-43	3.5-1, 092	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Galvanized steel	Air - indoor uncontrolled	None	None	III.B3.TP-8	3.5-1, 095	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B3.T-37a	3.5-1, 100	A

Table 3.5.2-36, Structural Commodities (Electrical Panels, Racks, Cabinets, and Other Enclosures) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B3.T-37a	3.5-1, 100	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B3.T-37a	3.5-1, 100	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B3.T-37a	3.5-1, 100	A

Table 3.5.2-36, Structural Commodities (Equipment Supports and Foundations) - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - indoor uncontrolled	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B4.TP-42	3.5-1, 055	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - outdoor	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B4.TP-42	3.5-1, 055	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Groundwater / soil	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B4.TP-42	3.5-1, 055	G, 1
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Groundwater / soil	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B5.TP-42	3.5-1, 055	G, 1
Constant and variable load spring hangers; guides; stops	Structural Support	Steel	Air - indoor uncontrolled	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.T-28	3.5-1, 057	A

Table 3.5.2-36, Structural Commodities (Equipment Supports and Foundations) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Sliding surfaces	Structural Support	Lubrite®	Air - indoor uncontrolled	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-45	3.5-1, 075	A, 4
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B4.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B4.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B4.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B4.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Stainless Steel	Concrete	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Stainless Steel	Water - flowing	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Stainless Steel	Water - standing	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B4.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B4.TP-261	3.5-1, 088	A

Table 3.5.2-36, Structural Commodities (Equipment Supports and Foundations) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B4.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B4.TP-261	3.5-1, 088	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting corrosion	Structures Monitoring (B.2.1.33)	III.B4.TP-43	3.5-1, 092	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B4.TP-43	3.5-1, 092	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B4.TP-6	3.5-1, 093	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Galvanized steel	Air - indoor uncontrolled	None	None	III.B4.TP-8	3.5-1, 095	A
Vibration isolation elements	Structural Support	Non-metallic (e.g., rubber)	Air - indoor uncontrolled	Reduction or loss of isolation function due to radiation hardening, temperature, humidity, sustained vibratory loading	Structures Monitoring (B.2.1.33)	III.B4.TP-44	3.5-1, 094	A

Table 3.5.2-36, Structural Commodities (Hazard Barriers and Elastomers) - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Controlled Leakage Door	Fire Barrier, Flood Barrier, HELB Shielding, Missile Barrier, Pressure Boundary, Shelter and Protection	Stainless Steel	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5-1, 100	C
Controlled Leakage Door	Fire Barrier, HELB Shielding, Pressure Boundary, Shelter and Protection, Flood Barrier	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A2.TP-302	3.5-1, 077	C
Controlled Leakage Door	Fire Barrier, Pressure Boundary, Shelter and Protection, Flood Barrier	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A2.TP-302	3.5-1, 077	C
Controlled Leakage Door	Fire Barrier, HELB Shielding, Pressure Boundary, Shelter and Protection, Flood Barrier	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	C

Table 3.5.2-36, Structural Commodities (Hazard Barriers and Elastomers) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Controlled Leakage Door	Fire Barrier, Pressure Boundary, Shelter and Protection, Flood Barrier	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	C
Controlled Leakage Door	Fire Barrier, Pressure Boundary, Shelter and Protection, Flood Barrier	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	"Inspection of Water-Control Structures Associated with Nuclear Power Plants"	III.A6.TP-221	3.5-1, 083	C
Controlled Leakage Door	Fire Barrier, Flood Barrier, HELB Shielding, Missile Barrier, Pressure Boundary, Shelter and Protection	Non-ferrous - copper alloys	Air - indoor uncontrolled	Loss of material due to mechanical wear	Structures Monitoring (B.2.1.33)	N/A	N/A	J, 3
Controlled Leakage Door	Fire Barrier, Flood Barrier, Missile Barrier, Pressure Boundary, Shelter and Protection	Non-ferrous - copper alloys	Air - outdoor	Loss of material due to mechanical wear	Structures Monitoring (B.2.1.33)	N/A	N/A	J, 3
Controlled Leakage Door	Fire Barrier, Flood Barrier, Missile Barrier, Pressure Boundary, Shelter and Protection	Stainless Steel	Air - outdoor	Loss of material due to mechanical wear	Structures Monitoring (B.2.1.33)	N/A	N/A	J, 3

Table 3.5.2-36, Structural Commodities (Hazard Barriers and Elastomers) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Controlled Leakage Door	Fire Barrier, Flood Barrier, HELB Shielding, Missile Barrier, Pressure Boundary, Shelter and Protection	Steel	Air - indoor uncontrolled	Loss of material due to mechanical wear	Structures Monitoring (B.2.1.33)	N/A	N/A	J, 3
Controlled Leakage Door	Fire Barrier, Pressure Boundary, Shelter and Protection, Flood Barrier	Steel	Air - outdoor	Loss of material due to mechanical wear	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	N/A	N/A	J, 3
Fire barrier penetration seals	Fire Barrier, Flood Barrier	Elastomer	Air - indoor uncontrolled	Hardening, loss of strength, shrinkage due to elastomer degradation	Fire Protection (B.2.1.15)	VII.G.A-19	3.3-1, 057	A
Fire barrier penetration seals	Fire Barrier, Flood Barrier	Grout	Air - indoor uncontrolled	Hardening, loss of strength, shrinkage due to elastomer degradation	Fire Protection (B.2.1.15)	VII.G.A-19	3.3-1, 057	F, 15
Fire Dampers	Fire Barrier, Pressure Boundary, Structural Support	Steel	Air	Loss of material due to general, pitting, crevice corrosion	Fire Protection (B.2.1.15)	VII.G.A-789	3.3-1, 255	A
Fire Rated Doors	Fire Barrier, Flood barrier	Steel	Air	Loss of material due to wear	Fire Protection (B.2.1.15)	VII.G.A-21	3.3-1, 059	A

Table 3.5.2-36, Structural Commodities (Hazard Barriers and Elastomers) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Structural Fire Barriers: walls, ceilings and floors	Fire Barrier	Reinforced Concrete	Air - indoor uncontrolled	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, or scaling	Fire Protection (B.2.1.15) and Structures Monitoring (B.2.1.33)	VII.G.A-90	3.3-1, 060	A, 16
Structural Fire Barriers: walls, ceilings and floors	Fire Barrier	Reinforced Concrete	Air - outdoor	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, or scaling	Fire Protection (B.2.1.15) and Structures Monitoring (B.2.1.33)	VII.G.A-90	3.3-1, 060	A, 16
Structural Fire Barriers: walls, ceilings and floors	Fire Barrier	Steel	Air - indoor uncontrolled	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, or scaling	Fire Protection (B.2.1.15) and Structures Monitoring (B.2.1.33)	VII.G.A-90	3.3-1, 060	F, 16
Structural Fire Barriers: walls, ceilings and floors	Fire Barrier	Steel	Air - outdoor	Cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, or scaling	Fire Protection (B.2.1.15) and Structures Monitoring (B.2.1.33)	VII.G.A-90	3.3-1, 060	F, 16

Table 3.5.2-36, Structural Commodities (Hazard Barriers and Elastomers) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural Fire Barrier Walls	Fire Barrier	Masonry Walls	Air - indoor uncontrolled	Cracking due to restraint shrinkage, creep, aggressive environment	Fire Protection (B.2.1.15) and Masonry Walls (B.2.1.32)	VII.G.A-626	3.3-1, 179	A
Fire Barriers	Fire Barrier	Subliming compounds (Thermolag®, and other similar materials)	Air - indoor uncontrolled	Cracking due to vibration. Loss of material due to abrasion, flaking	Fire Protection (B.2.1.15)	VII.G.A-805	3.3-1, 267	A
Fireproofing; fire barriers	Fire Barrier	Cementitious coatings (flamemastic; and other similar materials)	Air	Loss of material due to abrasion, exfoliation, elevated temperature, flaking, spalling; cracking/ delamination due to chemical reaction, elevated temperature, settlement, vibration; change in material properties due to elevated temperature, gamma irradiation exposure; separation	Fire Protection (B.2.1.15)	VII.G.A-806	3.3-1, 268	A
Fireproofing; fire barriers	Fire Barrier	Silicates (Marinite®, or other similar materials)	Air	Loss of material due to abrasion, flaking; cracking/delamination due to settlement; change in material properties due to gamma irradiation exposure; separation	Fire Protection (B.2.1.15)	VII.G.A-807	3.3-1, 269	A
Fire Barriers	Fire Barrier	Steel	Air - indoor uncontrolled	Loss of material due to wear	Fire Protection (B.2.1.15)	VII.G.A-21	3.3-1, 059	C

Table 3.5.2-36, Structural Commodities (Hazard Barriers and Elastomers) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Fire Barriers	Fire Barrier	Ceramic Fiber	Air - indoor uncontrolled	Loss of material due to abrasion, flaking; cracking/delamination due to settlement; change in material properties due to gamma irradiation exposure; separation	Fire Protection (B.2.1.15)	VII.G.A-807	3.3-1, 269	A
Fireproofing; fire barriers	Fire Barrier	Coatings (ALBI CLAD-161)	Air - indoor uncontrolled	Loss of material due to abrasion, flaking; cracking/delamination due to settlement; change in material properties due to gamma irradiation exposure; separation	Fire Protection (B.2.1.15)	VII.G.A-807	3.3-1, 269	A
Fireproofing; fire barriers	Fire Barrier	Gypsum	Air - indoor uncontrolled	Loss of material due to abrasion, flaking; cracking/delamination due to settlement; change in material properties due to gamma irradiation exposure; separation	Fire Protection (B.2.1.15)	VII.G.A-806	3.3-1, 268	A, 10
Moisture barriers (caulking, flashing, other sealants)	Shelter and Protection	Elastomer, rubber and other similar materials	Air - indoor uncontrolled	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	ASME Section XI, Subsection IWE (B.2.1.29)	II.B4.CP-40	3.5-1, 026	A
Radiation protection blankets	Shielding	Lead blankets (SS Mesh)	Air - indoor uncontrolled	SS mesh cracking, decomposition due to general degradation	Structures Monitoring (B.2.1.33)	None	None	J, 7

Table 3.5.2-36, Structural Commodities (Hazard Barriers and Elastomers) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Membrane	Shelter and Protection	Membrane (three-ply asphalt impregnated water seal)	Air - outdoor	Loss of weatherproofing integrity due to cracking, drying, organic decomposition, separation, shrinkage, wear, weathering.	Structures Monitoring (B.2.1.33)	None	None	J, 11
Compressible Joints and Seals	Flood Barrier, Pressure Boundary	Elastomer	Air - indoor uncontrolled	Hardening or loss of strength due to elastomer degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3-1, 076	A
Compressible Joints and Seals	Flood Barrier, Pressure Boundary	Elastomer	Air - outdoor	Hardening or loss of strength due to elastomer degradation	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.AP-102	3.3-1, 076	A
Compressible Joints and Seals	Flood Barrier, Pressure Boundary	Elastomer	Concrete	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	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797A	3.3-1, 263	C
Compressible Joints and Seals	Flood Barrier, Pressure Boundary	Elastomer	Raw water	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	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797A	3.3-1, 263	C

Table 3.5.2-36, Structural Commodities (Hazard Barriers and Elastomers) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Compressible Joints and Seals	Flood Barrier, Pressure Boundary	Elastomer	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	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797A	3.3-1, 263	C
Compressible Joints and Seals	Flood Barrier, Pressure Boundary	Elastomer	Treated Water	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	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797A	3.3-1, 263	C
Compressible Joints and Seals	Flood Barrier, Pressure Boundary	Elastomer	Underground	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	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797A	3.3-1, 263	C
Compressible Joints and Seals	Flood Barrier, Pressure Boundary	Elastomer	Air - indoor uncontrolled	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-41	3.5-1, 033	A

Table 3.5.2-36, Structural Commodities (Hazard Barriers and Elastomers) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Seals; gaskets; moisture barriers (caulking, flashing, and other sealants)	Flood Protection, Pressure Boundary	Elastomer	Air - indoor uncontrolled	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	Structures Monitoring (B.2.1.33)	III.A6.TP-7	3.5-1, 072	A
Seals; gaskets; moisture barriers (caulking, flashing, and other sealants)	Flood Protection, Pressure Boundary	Elastomer	Air - outdoor	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	Structures Monitoring (B.2.1.33)	III.A6.TP-7	3.5-1, 072	A
Seals; gaskets; moisture barriers (spent fuel pool gates)	Water Retaining Boundary	Elastomer	Air - indoor uncontrolled	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	Structures Monitoring (B.2.1.33)	III.A6.TP-7	3.5-1, 072	A
Seals; gaskets; moisture barriers (spent fuel pool gates)	Water Retaining Boundary	Elastomer	Treated Water	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	Structures Monitoring (B.2.1.33)	III.A6.TP-7	3.5-1, 072	A
Compressible Joints and Seals	Flood Barrier, Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A2.TP-302	3.5-1, 077	C
Seals; gaskets; moisture barriers (caulking, flashing, and other sealants)	Flood Protection, Pressure Boundary	Elastomer	Air - indoor uncontrolled	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	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797A	3.3-1, 263	C

Table 3.5.2-36, Structural Commodities (Hazard Barriers and Elastomers) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Seals; gaskets; moisture barriers (caulking, flashing, and other sealants)	Flood Protection, Pressure Boundary	Elastomer	Air - outdoor	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	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797A	3.3-1, 263	C
Seals; gaskets; moisture barriers (caulking, flashing, and other sealants)	Flood Protection, Pressure Boundary	Elastomer	Concrete	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	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797A	3.3-1, 263	C
Seals; gaskets; moisture barriers (caulking, flashing, and other sealants)	Flood Protection, Pressure Boundary	Elastomer	Raw water	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	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797A	3.3-1, 263	C

Table 3.5.2-36, Structural Commodities (Hazard Barriers and Elastomers) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Seals; gaskets; moisture barriers (caulking, flashing, and other sealants)	Flood Protection, Pressure Boundary	Elastomer	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	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797A	3.3-1, 263	C
Seals; gaskets; moisture barriers (caulking, flashing, and other sealants)	Flood Protection, Pressure Boundary	Elastomer	Underground	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	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-797A	3.3-1, 263	C
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Concrete	None	None	V.F.EP-112	3.2-1, 055	C
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A2.TP-302	3.5-1, 077	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A2.TP-302	3.5-1, 077	A

Table 3.5.2-36, Structural Commodities (Hazard Barriers and Elastomers) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A4.TP-302	3.5-1, 077	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A4.TP-302	3.5-1, 077	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A5.TP-302	3.5-1, 077	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A5.TP-302	3.5-1, 077	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A7.TP-302	3.5-1, 077	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A7.TP-302	3.5-1, 077	A

Table 3.5.2-36, Structural Commodities (Hazard Barriers and Elastomers) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A8.TP-302	3.5-1, 077	A
Steel components: all structural steel	Shelter and Protection, Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A8.TP-302	3.5-1, 077	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B5.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B5.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B5.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B5.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5-1, 088	A

Table 3.5.2-36, Structural Commodities (HVAC Duct Supports) - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - indoor uncontrolled	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B2.TP-42	3.5-1, 055	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - outdoor	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B2.TP-42	3.5-1, 055	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - indoor uncontrolled	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B4.TP-42	3.5-1, 055	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - outdoor	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B4.TP-42	3.5-1, 055	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-248	3.5-1, 080	A

Table 3.5.2-36, Structural Commodities (HVAC Duct Supports) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B4.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B4.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B4.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B4.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B4.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B4.TP-261	3.5-1, 088	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-43	3.5-1, 092	A

Table 3.5.2-36, Structural Commodities (HVAC Duct Supports) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-43	3.5-1, 092	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting corrosion	Structures Monitoring (B.2.1.33)	III.B4.TP-43	3.5-1, 092	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting corrosion	Structures Monitoring (B.2.1.33)	III.B4.TP-43	3.5-1, 092	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-6	3.5-1, 093	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Galvanized steel	Air - indoor uncontrolled	None	None	III.B2.TP-8	3.5-1, 095	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Galvanized steel	Air - indoor uncontrolled	None	None	III.B4.TP-8	3.5-1, 095	A

Table 3.5.2-36, Structural Commodities (HVAC Duct Supports) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Air	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Air	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Air	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B4.T-37a	3.5-1, 100	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B4.T-37a	3.5-1, 100	A

Table 3.5.2-36, Structural Commodities (HVAC Duct Supports) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Air	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B4.T-37a	3.5-1, 100	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B4.T-37a	3.5-1, 100	A

Table 3.5.2-36, Structural Commodities (Miscellaneous Steel) - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - indoor uncontrolled	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B5.TP-42	3.5-1, 055	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - outdoor	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B5.TP-42	3.5-1, 055	A
Equipment Hatch, CRD Hatch	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	None	None	II.B4.CP-37	3.5-1, 027	I, 9
Equipment Hatch, CRD Hatch	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	ASME Section XI, Subsection IWE (B.2.1.29) and 10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.C-16	3.5-1, 028	A

Table 3.5.2-36, Structural Commodities (Miscellaneous Steel) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Equipment Hatch, CRD Hatch	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of leak tightness in closed position due to mechanical wear	ASME Section XI, Subsection IWE (B.2.1.29) and 10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-39	3.5-1, 029	A
Hatches / Plugs	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel	Concrete	None	None	V.F.EP-112	3.2-1, 055	C
Steel components: all structural steel	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel	Concrete	None	None	V.F.EP-112	3.2-1, 055	C
Hatches / Plugs	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A2.TP-302	3.5-1, 077	C
Steel components: all structural steel	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A2.TP-302	3.5-1, 077	A

Table 3.5.2-36, Structural Commodities (Miscellaneous Steel) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Steel components: all structural steel	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A2.TP-302	3.5-1, 077	A
Hatches / Plugs	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	C
Steel components: all structural steel	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Hatches / Plugs	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	C
Steel components: all structural steel	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A

Table 3.5.2-36, Structural Commodities (Miscellaneous Steel) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Steel components: all structural steel	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A4.TP-302	3.5-1, 077	A
Steel components: all structural steel	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel	Treated Water	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A4.TP-302	3.5-1, 077	G, 2
Steel components: all structural steel	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A8.TP-302	3.5-1, 077	A
Steel components: all structural steel	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A8.TP-302	3.5-1, 077	A
Hatches / Plugs	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A9.TP-248	3.5-1, 080	C

Table 3.5.2-36, Structural Commodities (Miscellaneous Steel) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Steel components: all structural steel	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A9.TP-248	3.5-1, 080	C
Steel components: all structural steel	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5-1, 083	C
Steel components: all structural steel	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5-1, 083	C
Steel components: all structural steel	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel	Water - flowing	Loss of material due to corrosion	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5-1, 083	C
Steel components: all structural steel	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Stainless Steel	Air - outdoor	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5-1, 100	C

Table 3.5.2-36, Structural Commodities (Miscellaneous Steel) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Steel components: all structural steel	Flood Barrier, Pressure Boundary, Shelter and Protection, Structural Support	Stainless Steel	Raw Water	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5-1, 100	G, 2
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B5.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B5.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B5.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B5.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Concrete	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Concrete	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5-1, 088	A

Table 3.5.2-36, Structural Commodities (Miscellaneous Steel) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting corrosion	Structures Monitoring (B.2.1.33)	III.B5.TP-43	3.5-1, 092	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B5.TP-43	3.5-1, 092	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Galvanized steel	Air - indoor uncontrolled	None	None	III.B5.TP-8	3.5-1, 095	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5-1, 100	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5-1, 100	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5-1, 100	A

Table 3.5.2-36, Structural Commodities (Penetrations and Sleeves) - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - indoor uncontrolled	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B2.TP-42	3.5-1, 055	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - outdoor	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B2.TP-42	3.5-1, 055	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - indoor uncontrolled	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B3.TP-42	3.5-1, 055	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - outdoor	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B4.TP-42	3.5-1, 055	A

Table 3.5.2-36, Structural Commodities (Penetrations and Sleeves) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Penetrations; electrical and I&C	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Steel	Concrete	None	None	V.F.EP-112	3.2-1, 055	C
Penetrations; mechanical	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Steel	Concrete	None	None	V.F.EP-112	3.2-1, 055	C
Penetration sleeves	Flood barrier, Pressure Boundary, Shelter and Protection, Structural Support	Stainless steel; Dissimilar metal welds	Air - indoor uncontrolled	None	None	II.B4.CP-37	3.5-1, 027	I, 9
Penetration sleeves	Flood barrier, Pressure Boundary, Shelter and Protection, Structural Support	Stainless steel; Dissimilar metal welds	Air - indoor uncontrolled	Cracking due to SCC	ASME Section XI, Subsection IWE (B.2.1.29) and 10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-38	3.5-1, 010	A
Penetrations; electrical and I&C	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Stainless steel; Dissimilar metal welds	Air - indoor uncontrolled	Cracking due to SCC	ASME Section XI, Subsection IWE (B.2.1.29) and 10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-38	3.5-1, 010	C

Table 3.5.2-36, Structural Commodities (Penetrations and Sleeves) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Penetration sleeves	Flood barrier, Pressure Boundary, Shelter and Protection, Structural Support	Steel; Dissimilar metal welds	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	ASME Section XI, Subsection IWE (B.2.1.29) and 10 CFR Part 50, Appendix J (B.2.1.31)	II.B4.CP-36	3.5-1, 035	A
Penetrations; electrical and I&C	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A2.TP-302	3.5-1, 077	C
Penetrations; mechanical	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A2.TP-302	3.5-1, 077	C
Penetrations; electrical and I&C	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	C
Penetrations; mechanical	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	C

Table 3.5.2-36, Structural Commodities (Penetrations and Sleeves) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Steel components: penetrations	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	C
Penetrations; electrical and I&C	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	C
Penetrations; mechanical	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	C
Steel components: penetrations	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	C
Penetrations; electrical and I&C	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A8.TP-302	3.5-1, 077	C

Table 3.5.2-36, Structural Commodities (Penetrations and Sleeves) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Penetrations; mechanical	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A8.TP-302	3.5-1, 077	C
Penetrations; electrical and I&C	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Galvanized Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A9.TP-274	3.5-1, 082	C
Penetrations; mechanical	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A9.TP-274	3.5-1, 082	C
Penetrations; mechanical	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Steel	Groundwater / soil	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A9.TP-274	3.5-1, 082	C
Penetrations; electrical and I&C	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5-1, 083	C

Table 3.5.2-36, Structural Commodities (Penetrations and Sleeves) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Penetrations; mechanical	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5-1, 083	C
Penetrations; electrical and I&C	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5-1, 083	C
Penetrations; electrical and I&C	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Non-ferrous - aluminum	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5-1, 100	C
Penetrations; electrical and I&C	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Non-ferrous - aluminum	Air - outdoor	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5-1, 100	C
Penetrations; electrical and I&C	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Non-ferrous - aluminum	Concrete	Cracking due to SCC	One-Time Inspection (B.2.1.20)	VIII.G.S-450b	3.4-1, 102	C

Table 3.5.2-36, Structural Commodities (Penetrations and Sleeves) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Penetrations; mechanical	Shelter and Protection, Structural Support , Flood Barrier, Pressure Boundary	Stainless Steel	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5-1, 100	C
Penetrations; mechanical	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Stainless Steel	Concrete	None	None	V.F.EP-20	3.2-1, 091	C
Penetrations; mechanical	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Non-ferrous - copper alloys	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5-1, 100	J, 13
Penetrations; mechanical	Shelter and Protection, Structural Support, Flood Barrier, Pressure Boundary	Permali	Air - indoor uncontrolled	None	None	III.B5.T-37a	3.5-1, 100	J, 14
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-248	3.5-1, 080	A

Table 3.5.2-36, Structural Commodities (Penetrations and Sleeves) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B4.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B4.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B5.TP-248	3.5-1, 080	A
Structural Bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-226	3.5-1, 081	A
Structural Bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-226	3.5-1, 081	A
Structural Bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-226	3.5-1, 081	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B4.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B4.TP-274	3.5-1, 082	A

Table 3.5.2-36, Structural Commodities (Penetrations and Sleeves) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Galvanized Steel	Concrete	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Steel	Concrete	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Galvanized Steel	Concrete	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Galvanized Steel	Groundwater / soil	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5-1, 087	A

Table 3.5.2-36, Structural Commodities (Penetrations and Sleeves) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Structural bolting	Structural Support	Steel	Concrete	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Steel	Groundwater / soil	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Galvanized Steel	Concrete	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Galvanized Steel	Groundwater / soil	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Steel	Concrete	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Steel	Groundwater / soil	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-229	3.5-1, 087	A

Table 3.5.2-36, Structural Commodities (Penetrations and Sleeves) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Concrete	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Groundwater / soil	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Concrete	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Groundwater / soil	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B4.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B4.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Concrete	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B4.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Groundwater / soil	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B4.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B4.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B4.TP-261	3.5-1, 088	A

Table 3.5.2-36, Structural Commodities (Penetrations and Sleeves) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Structural bolting	Structural Support	Steel	Concrete	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B4.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Groundwater / soil	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B4.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Concrete	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Groundwater / soil	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Concrete	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Groundwater / soil	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5-1, 088	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting corrosion	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.T-24	3.5-1, 091	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting corrosion	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.T-24	3.5-1, 091	A

Table 3.5.2-36, Structural Commodities (Penetrations and Sleeves) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting corrosion	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.T-24	3.5-1, 091	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-43	3.5-1, 092	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-43	3.5-1, 092	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting corrosion	Structures Monitoring (B.2.1.33)	III.B4.TP-43	3.5-1, 092	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting corrosion	Structures Monitoring (B.2.1.33)	III.B4.TP-43	3.5-1, 092	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting corrosion	Structures Monitoring (B.2.1.33)	III.B5.TP-43	3.5-1, 092	A

Table 3.5.2-36, Structural Commodities (Penetrations and Sleeves) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-6	3.5-1, 093	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B4.TP-6	3.5-1, 093	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Galvanized steel	Air - indoor uncontrolled	None	None	III.B2.TP-8	3.5-1, 095	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Air	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B1.1.T-36a	3.5-1, 099	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B1.1.T-36a	3.5-1, 099	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Air	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B1.1.T-36a	3.5-1, 099	A

Table 3.5.2-36, Structural Commodities (Penetrations and Sleeves) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B1.1.T-36a	3.5-1, 099	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Air	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B1.2.T-36a	3.5-1, 099	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B1.2.T-36a	3.5-1, 099	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Air	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B1.2.T-36a	3.5-1, 099	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B1.2.T-36a	3.5-1, 099	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Air	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B1.3.T-36a	3.5-1, 099	A

Table 3.5.2-36, Structural Commodities (Penetrations and Sleeves) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B1.3.T-36a	3.5-1, 099	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Air	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B1.3.T-36a	3.5-1, 099	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B1.3.T-36a	3.5-1, 099	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B3.T-37a	3.5-1, 100	A

Table 3.5.2-36, Structural Commodities (Penetrations and Sleeves) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B3.T-37a	3.5-1, 100	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5-1, 100	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5-1, 100	A

Table 3.5.2-36, Structural Commodities (Pilings) - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Steel components: piles	Structural Support	Steel	Concrete	None	None	V.F.EP-112	3.2-1, 055	C
Steel components: piles	Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-219	3.5-1, 079	G, 5
Steel components: piles	Structural Support	Steel	Groundwater / soil	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-219	3.5-1, 079	A
Steel components: piles	Structural Support	Steel	Raw Water	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-219	3.5-1, 079	G, 6
Steel components: piles	Structural Support	Steel	Air - outdoor	Loss of material due to corrosion	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5-1, 083	C
Steel components: piles	Structural Support	Steel	Water - flowing	Loss of material due to corrosion	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5-1, 083	C
Steel components: piles	Structural Support	Steel	Water - standing	Loss of material due to corrosion	Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.34)	III.A6.TP-221	3.5-1, 083	C

Table 3.5.2-36, Structural Commodities (Pipe Whip Restraints and Jet Impingement Shields) - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - indoor uncontrolled	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B5.TP-42	3.5-1, 055	A
Pipe Whip Restraints and Jet Impingement Shields	Pipe Whip Restraint, HELB Shielding	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting corrosion	Structures Monitoring (B.2.1.33)	III.B5.TP-43	3.5-1, 092	C
Pipe Whip Restraints and Jet Impingement Shields	Pipe Whip Restraint, HELB Shielding	Stainless Steel	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5-1, 100	C
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B5.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B5.TP-261	3.5-1, 088	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting corrosion	Structures Monitoring (B.2.1.33)	III.B5.TP-43	3.5-1, 092	A

Table 3.5.2-36, Structural Commodities (Pipe Whip Restraints and Jet Impingement Shields) - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Galvanized steel	Air - indoor uncontrolled	None	None	III.B5.TP-8	3.5-1, 095	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Air	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5-1, 100	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B5.T-37a	3.5-1, 100	A

Table 3.5.2-36, Structural Commodities (Piping Supports) - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - indoor uncontrolled	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B1.1.TP-42	3.5-1, 055	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - indoor uncontrolled	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B1.2.TP-42	3.5-1, 055	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - outdoor	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B1.2.TP-42	3.5-1, 055	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - indoor uncontrolled	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B1.3.TP-42	3.5-1, 055	A

Table 3.5.2-36, Structural Commodities (Piping Supports) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - indoor uncontrolled	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B2.TP-42	3.5-1, 055	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - outdoor	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B2.TP-42	3.5-1, 055	A
Constant and variable load spring hangers; guides; stops	Structural Support	Stainless Steel	Air - indoor uncontrolled	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.T-28	3.5-1, 057	A
Constant and variable load spring hangers; guides; stops	Structural Support	Steel	Air - indoor uncontrolled	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.T-28	3.5-1, 057	A
Constant and variable load spring hangers; guides; stops	Structural Support	Stainless Steel	Air - indoor uncontrolled	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.T-28	3.5-1, 057	A
Constant and variable load spring hangers; guides; stops	Structural Support	Steel	Air - indoor uncontrolled	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.T-28	3.5-1, 057	A

Table 3.5.2-36, Structural Commodities (Piping Supports) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Constant and variable load spring hangers; guides; stops	Structural Support	Steel	Air - outdoor	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.T-28	3.5-1, 057	A
Constant and variable load spring hangers; guides; stops	Structural Support	Stainless steel	Air - indoor uncontrolled	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.T-28	3.5-1, 057	A
Constant and variable load spring hangers; guides; stops	Structural Support	Steel	Air - indoor uncontrolled	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.T-28	3.5-1, 057	A
Sliding surfaces	Structural Support	Steel	Air - indoor uncontrolled	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-45	3.5-1, 075	F, 12
Sliding surfaces	Structural Support	Lubrite®	Air - indoor uncontrolled	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-45	3.5-1, 075	A, 4
Sliding surfaces	Structural Support	Graphitic tool steel; Fluorogold; Lubrofluor	Air - indoor uncontrolled	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-45	3.5-1, 075	A

Table 3.5.2-36, Structural Commodities (Piping Supports) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Sliding surfaces	Structural Support	Non-ferrous - aluminum	Air - indoor uncontrolled	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-45	3.5-1, 075	F, 12
Sliding surfaces	Structural Support	Steel	Air - indoor uncontrolled	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-45	3.5-1, 075	F, 12
Sliding surfaces	Structural Support	Lubrite®	Air - indoor uncontrolled	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-45	3.5-1, 075	A, 4
Sliding surfaces	Structural Support	Graphitic tool steel; Fluorogold; Lubrofluor	Air - indoor uncontrolled	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-45	3.5-1, 075	A
Sliding surfaces	Structural Support	Non-ferrous - aluminum	Air - indoor uncontrolled	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-45	3.5-1, 075	F, 12
Sliding surfaces	Structural Support	Steel	Air - indoor uncontrolled	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-45	3.5-1, 075	F, 12
High-strength structural bolting	Structural Support	High-strength steel	Air	Cracking due to SCC	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-41	3.5-1, 068	A

Table 3.5.2-36, Structural Commodities (Piping Supports) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-248	3.5-1, 080	A
Structural Bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-226	3.5-1, 081	A
Structural Bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-226	3.5-1, 081	A
Structural Bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-226	3.5-1, 081	A
Structural Bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-226	3.5-1, 081	A
Structural Bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-226	3.5-1, 081	A
Structural bolting	Structural Support	Stainless steel	Treated water	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-232	3.5-1, 085	A
Structural bolting	Structural Support	Stainless steel	Treated water	Loss of material due to pitting, crevice corrosion	Water Chemistry (B.2.1.2) and ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-232	3.5-1, 085	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-235	3.5-1, 086	A

Table 3.5.2-36, Structural Commodities (Piping Supports) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-235	3.5-1, 086	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Galvanized Steel	Water - flowing	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Galvanized Steel	Water - standing	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Steel	Water - flowing	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5-1, 087	A

Table 3.5.2-36, Structural Commodities (Piping Supports) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Structural bolting	Structural Support	Steel	Water - standing	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Galvanized Steel	Water - flowing	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Galvanized Steel	Water - standing	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Steel	Water - flowing	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Steel	Water - standing	Loss of preload due to self-loosening	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.TP-229	3.5-1, 087	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A

Table 3.5.2-36, Structural Commodities (Piping Supports) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural bolting	Structural Support	Galvanized Steel	Water - flowing	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Water - standing	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Water - flowing	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Water - standing	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless Steel	Treated Water	Loss of material due to general (steel only), pitting, crevice corrosion	Water Chemistry (B.2.1.2) and ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-10	3.5-1, 090	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Treated Water	Loss of material due to general (steel only), pitting, crevice corrosion	Water Chemistry (B.2.1.2) and ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.TP-10	3.5-1, 090	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting corrosion	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.1.T-24	3.5-1, 091	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Cast Iron and Cast Iron Alloys	Air - outdoor	Loss of material due to general, pitting corrosion	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.T-24	3.5-1, 091	F, 2

Table 3.5.2-36, Structural Commodities (Piping Supports) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting corrosion	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.T-24	3.5-1, 091	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting corrosion	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.2.T-24	3.5-1, 091	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting corrosion	ASME Section XI, Subsection IWF (B.2.1.30)	III.B1.3.T-24	3.5-1, 091	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-43	3.5-1, 092	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-43	3.5-1, 092	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Treated Water	Loss of material due to general, pitting corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-43	3.5-1, 092	G, 2

Table 3.5.2-36, Structural Commodities (Piping Supports) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Galvanized steel	Air - indoor uncontrolled	None	None	III.B1.3.TP-8	3.5-1, 095	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B1.1.T-36a	3.5-1, 099	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B1.1.T-36a	3.5-1, 099	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B1.2.T-36a	3.5-1, 099	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B1.2.T-36a	3.5-1, 099	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Air	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B1.2.T-36a	3.5-1, 099	A

Table 3.5.2-36, Structural Commodities (Piping Supports) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B1.2.T-36a	3.5-1, 099	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B1.3.T-36a	3.5-1, 099	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B1.3.T-36a	3.5-1, 099	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Air	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B1.3.T-36a	3.5-1, 099	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B1.3.T-36a	3.5-1, 099	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	A

Table 3.5.2-36, Structural Commodities (Piping Supports) - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Aluminum	Air - outdoor	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Air - outdoor	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	A

Table 3.5.2-36, Structural Commodities (Thermal Insulation) - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Non-metallic thermal insulation	Thermal Insulation	Any	Air, condensation	Reduced thermal insulation resistance due to moisture intrusion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	IV.C1.R-450	3.1-1, 134	A
Non-metallic thermal Insulation	Thermal Insulation	Aluminum, calcium silicate, canvas, cement, ceramic fiber blanket, cloth fabric, fiberglass, foam, foil, glass, Kraft, Rockwool, vinyl plastic, wire fabric /mesh	Air, condensation	Reduced thermal insulation resistance due to moisture intrusion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-422	3.2-1, 087	A
Non-metallic insulation	Thermal Insulation	Asbestos, calcium silicate, cellular elastomeric, ceramic fiber blanket, corkmastic, fabricell, fiberglass, foam plastic, mineral wool	Air - indoor uncontrolled	Reduced thermal insulation resistance due to moisture intrusion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-704	3.3-1, 182	A

Table 3.5.2-36, Structural Commodities (Thermal Insulation) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Non-metallic insulation	Thermal Insulation	Asbestos, calcium silicate, cellular elastomeric, ceramic fiber blanket, corkmastic, fabricell, fiberglass, foam plastic, mineral wool	Air - outdoor	Reduced thermal insulation resistance due to moisture intrusion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-704	3.3-1, 182	A
Non-metallic insulation	Thermal Insulation	Any	Air, condensation	Reduced thermal insulation resistance due to moisture intrusion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-403	3.4-1, 064	A
Metallic thermal insulation	Thermal Insulation	metal reflective, stainless steel (mirror insulation)	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	C
Insulation jacketing	Thermal insulation jacket integrity	Aluminum, asbestos cloth, asphalt coating, glass fabric, canvas, cloth fabric, elastomers, polymer, PVC tape	Air - outdoor	Reduced thermal insulation resistance due to moisture intrusion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-704	3.3-1, 182	C

Table 3.5.2-36, Structural Commodities (Thermal Insulation) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Insulation jacketing	Thermal insulation jacket integrity	Aluminum, fiberglass, asbestos cloth, glass fabric, canvas, cloth fabric, elastomers, polymer, PVC tape	Air - indoor uncontrolled	Reduced thermal insulation resistance due to moisture intrusion	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-704	3.3-1, 182	C
Insulation jacketing	Thermal insulation jacket integrity	Galvanized steel	Air - indoor uncontrolled	None	None	III.B2.TP-8	3.5-1, 095	C
Insulation jacketing	Thermal insulation jacket integrity	Aluminum	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	C
Insulation jacketing	Thermal insulation jacket integrity	Aluminum	Air - outdoor	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	C
Insulation jacketing	Thermal insulation jacket integrity	Stainless steel	Air - indoor uncontrolled	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	C
Insulation jacketing	Thermal insulation jacket integrity	Stainless steel	Air - outdoor	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	C

Table 3.5.2-36, Structural Commodities (Tube Track) - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - indoor uncontrolled	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B2.TP-42	3.5-1, 055	A
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	Structural Support	Concrete; grout	Air - outdoor	Reduction in concrete anchor capacity due to local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Structures Monitoring (B.2.1.33)	III.B2.TP-42	3.5-1, 055	A
Sliding support bearings; sliding support surfaces	Structural Support	Steel	Air - indoor uncontrolled	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	Structures Monitoring (B.2.1.33)	III.B2.TP-46	3.5-1, 074	F, 8
Sliding support bearings; sliding support surfaces	Structural Support	Steel	Air - outdoor	Loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, overload, wear	Structures Monitoring (B.2.1.33)	III.B2.TP-47	3.5-1, 074	F, 8
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-248	3.5-1, 080	A

Table 3.5.2-36, Structural Commodities (Tube Track) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Stainless Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.B2.TP-261	3.5-1, 088	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-43	3.5-1, 092	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.B2.TP-43	3.5-1, 092	A
Support members; bolted connections; support anchorage to building structure	Structural Support	Galvanized steel	Air - indoor uncontrolled	None	None	III.B2.TP-8	3.5-1, 095	A

Table 3.5.2-36, Structural Commodities (Tube Track) - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Air	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	A
Support members; welds; bolted connections; support anchorage to building structure	Structural Support	Stainless steel	Condensation	Loss of material due to pitting and crevice corrosion, cracking due to SCC	One-Time Inspection (B.2.1.20)	III.B2.T-37a	3.5-1, 100	A

<u>Table 3.5.2-36 Notes</u>

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. The reduction in concrete anchor capacity of concrete at locations of expansion and grouted anchors will be managed in accordance with the Structures Monitoring program (B.2.1.33).
2. Consistent with NUREG-2191 Volume 2, steel, stainless steel, and cast iron materials are susceptible to corrosion. The Structures Monitoring program (B.2.1.33) will manage the loss of material due to corrosion for the steel fire barriers, stainless steel controlled leakage doors, miscellaneous structural steel, penetrations, pipe whip restraints and jet impingement shields, non-ASME stainless steel piping support members; welds; bolted connections; support anchorage to building structure; whereas the ASME Section XI, Subsection IWE program (B.2.1.29) will manage the ASME Class 2 cast iron, steel, and stainless steel piping support members; welds; bolted connects; support anchorage to building structure; and the One-Time Inspection program (B.2.1.20) will manage the loss of material and cracking due to SCC for the stainless steel and aluminum components in the Miscellaneous Steel commodity Group as well as for the stainless steel components in the Pipe Whip Restraints and Jet Impingement Shields Commodity Group.
3. The Structures Monitoring program (B.2.1.33) and the Inspection of Water-Control Structures Associated with Nuclear Power Plants program (B.2.1.34) will manage the loss of material due to mechanical wear, which occurs through the use of the door.

4. Lubrite is not susceptible to lockup due to wear. However, the ASME Section XI, Subsection IWF program (B.2.1.30) will continue to monitor the loss of mechanical function due to corrosion, distortion, dirt or debris accumulation, and overload.
5. The portions of the piles extending above grade are exposed to air - outdoors, which is potentially moist and conducive to promoting corrosion. The Structures Monitoring program (B.2.1.33) will manage the aging effect of corrosion for pilings exposed to an outdoor environment.
6. The NUREG 2191 Volume 2, notes that “other materials with prolonged exposures to groundwater or moist soils are subject to the same aging effects as those systems and components exposed to raw water;” therefore, the Structures Monitoring program (B.2.1.33) will manage the aging effect of corrosion for pilings exposed to groundwater/soil or raw water.
7. The Structures Monitoring program (B.2.1.33) will manage the degradation effects on SS Mesh.
8. Though noted for Class 1, NUREG 2191 Volume 2 notes that steel sliding surfaces can be susceptible to a loss of mechanical function. Conservatively, this aging effect will be monitored at BFN using the Structures Monitoring program (B.2.1.33) consistent with steel sliding surfaces being scoped into the Structures Monitoring Program by NUREG 2191 Volume 2.
9. A plant-specific further evaluation was performed on the noted components (metal liner, metal plate, airlock, equipment hatch, CRD hatch, and penetration sleeves) to demonstrate that cracking due to cyclic loading is an aging effect that does not require aging management for the components. The option to perform a fatigue waiver was used in lieu of managing for cracking due to cyclic loading with the 10 CFR Part 50, Appendix J program (B.2.1.31) and ASME Section XI, Subsection IWE program (B.2.1.29) via supplemental surface examinations or leak rate test.
10. The Fire Protection program (B.2.1.15) will manage the aging effects pertinent to fireproofing; fire barriers for non-silicate materials like gypsum.
11. The Structures Monitoring program (B.2.1.33) will manage the loss of weatherproofing for membrane that is exposed to the outdoor environment.
12. Regardless of the material, the class 1, 2, 3, and MC pipe support sliding surfaces will be managed with the ASME Section XI, Subsection IWF program (B.2.1.30), which will continue to monitor the loss of mechanical function.
13. Consistent with NUREG 2191 Volume 2, copper alloys have the potential for degradation due to corrosion. The One-Time Inspection program (B.2.1.20) will monitor this condition for mechanical penetrations.
14. Due to the other penetration materials susceptibility for corrosion, Permali mechanical penetrations will be monitored with the One-Time Inspection program (B.2.1.20).
15. The Fire Protection program (B.2.1.15) will manage the hardening, loss of strength for fire barrier penetration seals made of elastomers or grout.
16. This component type includes the combustible liquid retention curbs or dikes, for which the Structures Monitoring program (B.2.1.33) and Fire Protection program (B.2.1.15) will manage the cracking, corrosion, and/or loss of material for components with a concrete or steel material type.

Table 3.5.2-37, Isolation Valve Pits - Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): foundation	Shelter and Protection, Structural Support	Concrete	Groundwater/ soil	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-108	3.5-1, 042	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Groundwater/ soil	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete (inaccessible areas): all	Shelter and Protection, Structural Support	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-204	3.5-1, 043	A
Concrete: all	Shelter and Protection, Structural Support	Concrete	Soil	Cracking and distortion due to increased stress levels from settlement	Structures Monitoring (B.2.1.33)	III.A3.TP-30	3.5-1, 044	A

Table 3.5.2-37, Isolation Valve Pits - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (inaccessible areas): exterior above- and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-67	3.5-1, 047	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): all	Shelter and Protection, Structural Support	Concrete	Water - flowing	Cracking due to expansion from reaction with aggregates	Structures Monitoring (B.2.1.33)	III.A3.TP-25	3.5-1, 054	A
Concrete (accessible areas): exterior above- and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Water - flowing	Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation	Structures Monitoring (B.2.1.33)	III.A3.TP-24	3.5-1, 063	A
Concrete (accessible areas): exterior above- and below-grade; foundation	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring (B.2.1.33)	III.A3.TP-23	3.5-1, 064	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater/ soil	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-212	3.5-1, 065	A

Table 3.5.2-37, Isolation Valve Pits - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Concrete (accessible areas): interior	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete (accessible areas): above-grade exterior	Shelter and Protection, Structural Support	Concrete	Air - outdoor	Cracking; loss of bond; and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring (B.2.1.33)	III.A3.TP-26	3.5-1, 066	A
Concrete (inaccessible areas): below-grade exterior; foundation	Shelter and Protection, Structural Support	Concrete	Groundwater/ soil	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-29	3.5-1, 067	A
Concrete: interior	Shelter and Protection, Structural Support	Concrete	Air - indoor uncontrolled	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Concrete: above-grade exterior	Shelter and Protection, Structural Support	Concrete	Air-outdoor	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring (B.2.1.33)	III.A3.TP-28	3.5-1, 067	A
Steel components: all structural steel	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A
Steel components: all structural steel	Structural Support	Steel	Air-outdoor	Loss of material due to corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-302	3.5-1, 077	A

Table 3.5.2-37, Isolation Valve Pits - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Steel	Air-outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-248	3.5-1, 080	A
Structural bolting	Structural Support	Galvanized steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of material due to general, pitting, crevice corrosion	Structures Monitoring (B.2.1.33)	III.A3.TP-274	3.5-1, 082	A
Structural bolting	Structural Support	Galvanized Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Galvanized Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - indoor uncontrolled	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A
Structural bolting	Structural Support	Steel	Air - outdoor	Loss of preload due to self-loosening	Structures Monitoring (B.2.1.33)	III.A3.TP-261	3.5-1, 088	A

Table 3.5.2-37 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

None.

3.6 AGING MANAGMENT OF ELECTRICAL AND INSTRUMENTATION AND CONTROLS SYSTEMS

3.6.1 Introduction

This section provides the results of the aging management review for those components and commodities identified in Section 2.5, Scoping and Screening Results: Electrical, as being subject to aging management review. The components or commodities, which are addressed in this section are described in the indicated sections.

- Cable Connections (Metallic Parts) (2.5.2.5.1)
- Electrical Insulation for Electrical Cables and Connections (2.5.2.5.2)
    - Electrical Insulation for Electrical Cables and Connections, which includes:
        - Electrical Penetration Pigtails
        - Splices
        - Insulating Portion of Terminal Blocks
        - Insulating Portion of Fuse Holders (not part of active equipment).
    - Electrical Insulation for Electrical Cables and Connections Used in Instrumentation Circuits
    - Electrical Insulation for Inaccessible Medium Voltage Power Cables
    - Electrical Insulation for Inaccessible Instrumentation and Control Cables
    - Electrical Insulation for Inaccessible Low Voltage Power Cables
- Electrical Penetrations (2.5.2.5.3)
- Fuse Holders (not part of active equipment) (2.5.2.5.4)
- High Voltage Electrical Insulators (2.5.2.5.5)
- Metal Enclosed Bus (2.5.2.5.6)
- Switchyard Bus and Connections, Transmission Conductors, and Transmission Connectors (2.5.2.5.7)

The electrical and I&C commodity groups which are addressed in this section are described in the indicated sections. Electrical Penetrations are not subject to their own aging management review in this section in that they are addressed 1) as a TLAA in the Environmental Qualification of Electric Equipment (B.3.1.3) program and 2) in the Containments, Structures, and Component Supports aging management review (Section 3.5).

3.6.2 Results

The following tables summarize the results of the aging management review for electrical and I&C components and commodities.

- Table 3.6.2-1, Electrical and I&C Commodities – Summary of Aging Management Evaluation

3.6.2.1 Materials, Environments, Aging Effects Requiring Management And Aging Management Programs

3.6.2.1.1 Cable Connections (Metallic Parts)

Materials

The materials of construction for the Cable Connections (Metallic Parts) are:

- Various Metals Used for Electrical Contacts

Environments

The Cable Connections (Metallic Parts) 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 Cable Connections (Metallic Parts) require management:

- Increased Electrical Resistance of Connection

Aging Management Programs

The following aging management programs manage the aging effects for the Cable Connections (Metallic Parts):

- Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.43)

3.6.2.1.2 Electrical Insulation for Electrical Cables and Connections

The electrical insulation for electrical cables and connections commodity group was broken down for aging management review of insulation into subcategories based on categorization in NUREG-2191:

- Electrical Insulation for Electrical Cables and Connections
- Electrical Insulation for Electrical Cables and Connections Used in Instrumentation Circuits
- Electrical Insulation for Inaccessible Medium Voltage Power Cables
- Electrical Insulation for Inaccessible Instrumentation and Control Cables
- Electrical Insulation for Inaccessible Low Voltage Power Cables

This insulation material commodity group includes insulated cables and connections, electrical penetration pigtails, splices, insulating portions of terminal blocks, and insulating portions of fuse holders (not part of active equipment).

Materials

The materials of construction for the Electrical Insulation for Electrical Cables and Connections are:

- Various Organic Polymers

Environments

The Electrical Insulation for Electrical Cables and Connections are exposed to the following environments:

- Adverse Localized Environment caused by Heat, Radiation, or Moisture
- Adverse Localized Environment caused by Significant Moisture

Aging Effects Requiring Management

The following aging effects associated with the Electrical Insulation for Electrical Cables and Connections require management:

- Reduced Electrical Insulation Resistance
- Reduced Electrical Insulation Resistance or Degraded Dielectric Strength

Aging Management Programs

The following aging management programs manage the aging effects for the Electrical Insulation for Electrical Cables and Connections:

- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.36)
- Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (B.2.1.37)
- Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.38)
- Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.39)
- Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.40)

3.6.2.1.3 Fuse Holders (not part of active equipment)

Materials

The materials of construction for the Fuse Holders (not part of active equipment) Metallic Clamps are:

- Various Metals Used for Electrical Connections

The materials of construction for the Fuse Holders (not part of active equipment) Insulation Material are:

- Bakelite, Ceramic, Molded Polycarbonate, Other Organic Polymers, Phenolic Melamine

Environments

The Fuse Holders (not part of active equipment) Metallic Clamps and Insulation Material are exposed to the following environments:

- Air - Indoor, Controlled
- Air - Indoor, Uncontrolled

Aging Effects Requiring Management

The following aging effects associated with the Fuse Holders (not part of active equipment) require management:

- Increased electrical resistance of connection (for Metallic Clamps)
- Reduced electrical insulation resistance (for Insulation Materials)

Aging Management Programs

The following aging management programs manage the aging effects for the Fuse Holders (not part of active equipment):

- Fuse Holders (B.2.1.42)

3.6.2.1.4 High Voltage Electrical Insulators

Materials

The materials of construction for the High Voltage Electrical Insulators are:

- Porcelain, Malleable Iron, Aluminum, Galvanized Steel, Cement

Environments

The High Voltage Electrical Insulators are exposed to the following environments:

- Air - Outdoor

Aging Effects Requiring Management

The High Voltage Electrical Insulators have no aging effects requiring management. See subsection 3.6.2.3.1.

Aging Management Programs

Because there are no aging effects requiring management, no aging management programs are required for the High Voltage Electrical Insulators.

3.6.2.1.5 Metal Enclosed Bus

Materials

The materials of construction for the Metal Enclosed Bus; Bus/Connections; Electrical Insulation, Electrical Insulators; and External Surface of Enclosure Assemblies are:

- Various Metals Used for Electrical Bus and Connections
- Porcelain, Xenoy, Thermo-Plastic Organic Polymers
- Galvanized Steel, Aluminum

Environments

The Metal Enclosed Bus components 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 require management:

- Increased Electrical Resistance of Connection
- Reduced Electrical Insulation Resistance
- Loss of Material

Aging Management Programs

The following aging management programs manage the aging effects for the Metal Enclosed Bus:

- Metal Enclosed Bus (B.2.1.41)

3.6.2.1.6 Switchyard Bus and Connections

Materials

The materials of construction for the Switchyard Bus and Connections are:

- Aluminum, Stainless Steel, Copper, Bronze, Galvanized Steel

Environments

The Switchyard Bus and Connections are exposed to the following environments:

- Air - Outdoor

Aging Effects Requiring Management

The Switchyard Bus and Connections have no aging effects requiring management. See subsection 3.6.2.2.3 for further evaluation.

Aging Management Programs

Because there are no aging effects requiring management, no aging management programs are required for the Switchyard Bus and Connections.

3.6.2.1.7 Transmission Conductors

Materials

The materials of construction for the Transmission Conductors are:

- Aluminum, Steel

Environments

The Transmission Conductors are exposed to the following environments:

- Air - Outdoor

Aging Effects Requiring Management

The Transmission Conductors have no aging effects requiring management. See subsection 3.6.2.2.3 for further evaluation.

Aging Management Programs

Because there are no aging effects requiring management, no aging management programs are required for the Transmission Conductors.

3.6.2.1.8 Transmission Connectors

Materials

The materials of construction for the Transmission Connectors are:

- Aluminum, Steel

Environments

The Transmission Connectors are exposed to the following environments:

- Air - Outdoor

Aging Effects Requiring Management

The Transmission Connectors have no aging effects requiring management. See subsection 3.6.2.2.3 for further evaluation.

Aging Management Programs

Because there are no aging effects requiring management, no aging management programs are required for the Transmission Connectors.

3.6.2.2 AMR Results for Which Further Evaluation is Recommended by the GALL-SLR Report

NUREG-2191 provides the basis for identifying those programs that warrant further evaluation by the reviewer in the subsequent license renewal application. For the electrical commodities, those programs are addressed in the following subsections.

3.6.2.2.1 Electrical Equipment Subject to Environmental Qualification

Environmental qualification is a time-limited aging analysis (TLAA) as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The evaluation of this TLAA is addressed separately in Section 4.4, "Environmental Qualification (EQ) of Electrical Equipment," of this SRP-SLR.

Table 3.6.1 Item Number 3.6-1, 001: The evaluation of this TLAA is addressed in Section 4.4, Environmental Qualification of Electric Equipment, of this application.

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).

Table 3.6.1 Item Numbers 3.6-1, 029; 3.6-1, 030; 3.6-1, 031; and 3.6-1, 032: Not applicable. There are no Cable Bus: electrical insulation; insulators or Cable Bus: external surface of enclosure assemblies in Electrical Commodities because there is no cable bus, in the scope of subsequent license renewal, at BFN.

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).

<u>Table 3.6.1 Item Numbers 3.6-1, 004; 3.6-1, 005; 3.6-1, 021; and 3.6-1, 007:</u> ACSR Transmission Conductors; Transmission Connectors, Switchyard Bus and Connections; Aluminum Transmission Conductors; and Aluminum and Aluminum Conductor Steel Reinforced (ACSR)/ Aluminum Conductor Aluminum Alloy Reinforced (ACAR)/All Aluminum Conductor (AAC) Transmission Conductors. (BFN does not use ACAR conductors)

The transmission conductors, transmission connectors, and switchyard bus and connections evaluated for BFN are those that are part of the circuits which supply power from electric utility transmission system to plant buses, including connecting the alternate AC source in the event of a station blackout. These circuits provide power to in scope subsequent license renewal components used for coping during and recovery from an SBO event and during post fire safe shutdown, when offsite power is credited. The off-site and on-site AC Electrical Power Distribution System include the off-site AC power sources (preferred normal and alternate power sources). Each of four 4 kV shutdown boards has two off-site power supplies available. An off-site circuit consists of breakers, transformers, switches, interrupting devices, bus, cabling, protective relaying, and controls required to transmit power from the off-site transmission network to the 4kV shutdown boards. Off-site power is supplied to the 161 kV and 500 kV switchyards from the transmission network by seven transmission lines (two 161 kV lines and five 500 kV lines). The in scope commodities in the circuits for offsite power sources and the station blackout alternate ac source include 22 kV, 161 kV, and 500 kV transmission conductors, transmission connectors, switchyard bus and connections.

<u>Wind-Induced Abrasion and Fatigue - Transmission Conductors</u>

<u>Table 3.6.1 Item Number 3.6-1, 007</u>: ACSR and Aluminum Transmission Conductors: Transmission conductor vibration or sway could be caused by wind loading. Industry experience has shown that the 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 line to vibrate or sway is considered in design and installation. Therefore, the loss of material aging effect that could result from wind-induced transmission conductor vibration or sway is not applicable and

would not cause a loss of intended function for transmission conductors for the subsequent period of extended operation.

Corrosion - Transmission Conductors

Table 3.6.1 Item Numbers 3.6-1, 004 and 3.6-1, 021: ACSR Transmission Conductors and Aluminum Transmission Conductors, respectively: BFN has seven transmission conductor circuits within the scope of SLR in support of SBO. The first set are five 500 kV ACSR transmission conductor circuits routed as listed in the below table, “500 kV Transmission Routing.” These offsite transmission conductor circuits enter the BFN switchyard where the circuits transition to an aluminum bus network via a short span of aluminum conductors. Because these conductors are aluminum they are not subject to the aging effect of loss of conductor strength due to corrosion and therefore do not require aging management.

500 kV Transmission Routing		
From	To	Type
West Point	BFN	ACSR
Madison	BFN	ACSR
Maury	BFN	ACSR
Union	BFN	ACSR
Limestone	BFN	ACSR

Two 161 kV lines, one from Trinity Substation and a second from Athens Substation, both with aluminum steel supported (ACSS) transmission conductors, terminate into a 161 kV bus network in the BFN Switchyard.

The TVA Transmission and Distribution design practices follow the National Electrical Safety Code (NESC) methodologies. The NESC requires that tension on installed conductors be a maximum of 60 percent of the ultimate conductor strength. The NESC also sets the maximum tension of a conductor must be designed to withstand heavy load requirements, which include consideration of ice, wind, and temperature.

The most prevalent contribution to loss of conductor strength of an ACSR transmission conductor is corrosion, which includes corrosion of the steel core and aluminum strand pitting. For ACSR conductors, degradation begins as a loss of zinc from the galvanized steel core wires. Corrosion rates depend largely on air quality which includes suspended particles chemistry, sulfur dioxide concentration in air, precipitation, fog chemistry, and meteorological conditions.

The EPRI License Renewal Handbook discusses an Ontario Hydroelectric study that is documented in 1992 IEEE Transactions on Power Delivery. The papers present the methodology and results of both field and laboratory tests on ACSR conductors from Ontario Hydroelectric's older transmission lines. The field tests were performed on-line, to detect steel core galvanizing loss by using an overhead line conductor corrosion detector. Potential conductor degradation is measured by an eddy current sensor that travels along the conductor, between transmission towers. Laboratory tests were performed for fatigue, tensile strength, torsional ductility, and electrical performance. The fatigue tests simulating 50 years of service life were performed to assess existing cables as well as a new cable. The tensile strength was assessed by the individual wire method, and torsional ductility was assessed by the twist to failure method. Both the tensile strength and torsional ductility tests were performed in accordance with published standards. Additional considerations in the performance of these aging assessments included metallurgical data and analysis for potential environmental contributors. Tests performed by Ontario Hydroelectric showed a 30 percent loss of composite conductor strength of an 80-year-old ACSR conductor due to corrosion. The BFN in scope transmission conductors are the same type of transmission conductors evaluated in the Ontario Hydroelectric study and in the EPRI License Renewal Electrical Handbook. The test methodology as published in the IEEE Transactions on Power Delivery is applicable to in scope BFN ACSR transmission conductors.

The ACSS conductors used for the 161 kV overhead transmission lines are designed to operate continuously at higher temperatures up to 250 ºC without loss of strength, which allows for a significant increase in current carrying capacity over ACSR and has the same appearance as ACSR but the aluminum strands are a fully annealed temper soft aluminum alloy. The aluminum wires have a low yield strength which consequently forces a majority of the load into the steel wires. The unique feature about ACSS conductor is that it will sag less at high temperatures than will ACSR conductors, and is therefore often used to reconductor existing lines. Thus, ACSS is bounded by the ACSR analysis.

BFN is located in an area where industrial airborne particle concentrations are comparatively low, since it is located in a rural area with no heavy industry nearby. In the Ontario Hydroelectric Study, the conductors most affected by atmospheric corrosion were located in areas subject to pollution sources and a major urban area. Therefore, the environmental impact to the BFN transmission conductors (which are located in a rural area) are bounded by the Ontario Hydroelectric conductors (which were located in polluted and urban environments).

An example presented in the EPRI License Renewal Handbook, compares a 4/0 conductor to the results of the Ontario Hydroelectric Study. The EPRI License Renewal Electrical Handbook evaluation documents that a 4/0 ACSR conductor, which was included in the Ontario Hydroelectric study, has the smallest ultimate strength margin. Larger, more substantial transmission conductors that had a greater strength margin were bounded by the 4/0 ACSR conductor example. The BFN transmission conductors are physically more substantial than the limiting 4/0 ACSR conductor.

Assuming a 30 percent loss of strength as demonstrated by the Ontario Hydroelectric tests, there would still be sufficient margin between what is required by the NESC and actual conductor strength. With the NESC limits of tension on installed conductors being a maximum of 60 percent of the ultimate conductor strength and a maximum tension of a conductor that must be designed to withstand heavy load requirements, which include consideration of ice, wind, and temperature; a minimum of a 10% margin would exist for the BFN ACSR transmission conductors as they age. The design and physical construction of the BFN in scope transmission conductors during the subsequent period of extended operation is bounded by the handbook analysis of the 4/0 ACSR conductor and is also bounded by the Ontario Hydroelectric study.

The above evaluations demonstrate with reasonable assurance that transmission conductors will have ample strength margin through the subsequent period of extended operation. TVA Transmission/Power Supply personnel perform normal maintenance activities on all portions of the switchyards, including transmission conductors. These maintenance activities have not revealed any aging effects/mechanisms associated with transmission lines to date. In conclusion, there are no applicable aging effects that could cause loss of the intended function of the transmission conductors. Therefore, loss of conductor strength due to corrosion of transmission conductors, and confirmed by operating experience, is not an aging effect requiring management for the subsequent period of extended operation.

Oxidation or Loss of Pre-Load - Transmission Connectors

Table 3.6.1 Item Number 3.6-1, 005 Transmission Connectors: Transmission connectors employ good bolting practices. The connections are treated with corrosion inhibitors to avoid connection oxidation and torqued at the time of installation to avoid loss of pre-load. The transmission connectors are designed and installed using vibration absorption techniques to prevent loss of preload. Therefore, based on BFN design and confirmed by operating experience, oxidation and loss of preload are not applicable aging mechanisms for BFN transmission connectors.

Wind-Induced Abrasion and Fatigue - Switchyard Bus

Table 3.6.1 Item Number 3.6-1, 006 Switchyard Bus and Connections: BFN is located inland, in northern Alabama. Switchyard buses are connected to flexible conductors that do not normally vibrate and are supported by insulators and ultimately by static, structural components, such as concrete footings and structural steel. Switchyard bus is rigidly mounted and is therefore not subject to abrasion induced by wind loading. Therefore, based on BFN design and confirmed by operating experience, wind-induced abrasion and fatigue are not applicable aging mechanisms for BFN switchyard bus.

Oxidation or Loss of Pre-Load - Switchyard Bus Connections

Table 3.6.1 Item Number 3.6-1, 006 Switchyard Bus and Connections: Switchyard bus connections employ good bolting practices. The connections are treated with corrosion inhibitors to avoid connection oxidation and torqued at the time of installation to avoid loss of pre-load. The switchyard bus bolted connections are designed and installed using vibration absorption techniques to prevent loss of preload. Therefore, based on BFN design and confirmed by operating experience, oxidation and loss of preload are not applicable aging mechanisms for BFN switchyard bus connections.

Conclusion

TVA Transmission personnel perform normal maintenance activities on all portions of the switchyards, including transmission conductors. These maintenance activities have not revealed any aging effects/mechanisms associated with transmission lines to date. In conclusion, there are no applicable aging effects that could cause loss of the intended function of the transmission conductors. There are no applicable aging effects that could cause a loss of the intended function of the transmission conductors and connections and switchyard bus and connections. Therefore, loss of conductor strength due to corrosion of transmission conductors is not an aging effect requiring management for the period of extended operation.

3.6.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

QA provisions applicable to Subsequent License Renewal are discussed in Appendix A, Section A.1.4, and Appendix B, Section B.1.3.

3.6.2.2.5 Ongoing Review of Operating Experience

Ongoing review of operating experience is addressed in Appendix A, Section A.1.5, and Appendix B, Section B.1.4.

3.6.2.3 AMR Results Not Consistent With or Not Addressed in the GALL-SLR Report

3.6.2.3.1 High Voltage Electrical Insulators

Table 3.6.1 Item Numbers 3.6-1, 002 and 3.6-1, 003 High-Voltage Electrical Insulators:

The BFN in scope high voltage electrical insulators (HVIs), in the incoming offsite power source circuits and the alternate AC source for the SBO coping period, were evaluated for aging effects requiring management during aging management reviews. BFN has seven transmission conductor circuits within the scope of SLR in support of SBO. The first set are five 500 kV ACSR transmission conductors routed as listed in the below table, “500 kV Transmission Routing.” These offsite transmission conductors enter the BFN switchyard where the circuits transition to an aluminum bus network via a short span of aluminum conductors. Two 161 kV offsite sources; one from Trinity Substation and a second from Athens Substation with ACSS transmission conductors. These terminate into a 161 kV bus network.

The in scope insulators include:

- 500 kV insulators in offsite sources in the table below.

500 kV Transmission Routing		
From	To	Type
West Point	BFN	ACSR
Madison	BFN	ACSR
Maury	BFN	ACSR
Union	BFN	ACSR
Limestone	BFN	ACSR

- 161 kV insulators in offsite sources; one from Trinity Substation and a second from Athens Substation.

The in scope HVIs provide electrical insulation for switchyard bus, transmission conductors, switchyard active components, and associated connections that are part of the circuits that supply power from electric utility transmission system to plant buses, including connecting the alternate AC source in the event of a station black out. These circuits provide power to in scope license renewal components used for coping during and recovery from a station blackout event and during post fire safe shutdown, when offsite power is credited.

Airborne Contamination

Various airborne materials such as salt, dust, fog, cooling tower plume, foreign debris, or industrial effluents can contaminate insulator surfaces. An excessive buildup of surface contamination enables the conductor voltage to track along the surface more easily and can lead to insulator flashover. The buildup of surface contamination is gradual and in most areas, such contamination is washed away by rain, where the glazed insulator surface aids in contamination removal.

Excessive surface contamination can be a problem in areas where there are greater concentrations of airborne particles such as near the seacoast where salt spray is prevalent, dust, near industrial facilities that discharge airborne pollutants, or at sites where the cooling tower plume may deposit contaminants on switchyard components and transmission lines.

At BFN, the in scope HVIs; the 500 kV and 161 kV insulators were evaluated for susceptibility to airborne surface contamination from salt, dust, fog, cooling tower plume, foreign debris, and industrial effluents. BFN is not located in an environment conducive to accelerated aging. Considering potential airborne salt contamination, the HVIs are not located near a seacoast or near a brackish waterway. BFN is located inland, in northern Alabama where there is no source of airborne salt contamination. Considering potential airborne particulate contamination from industrial activities (i.e., soot), the HVIs are located in an area where industrial airborne particle concentrations are comparatively low, since it is located in a rural area with no heavy industry nearby. The nearest industrial facility is a steel plant located approximately 3.5 miles away.

Considering potential airborne particulate contamination from agricultural activities (i.e., dust), the HVIs are located in an area where agricultural airborne particle concentrations are possible since BFN is located in a rural area with agricultural activities nearby. The closest agricultural land is approximately 2805 feet away from the nearest HVIs. According to BFN FSAR, the lower level winds (i.e., winds at 33 feet) have the highest frequency of winds generally from the southeast; upper level winds (i.e., winds at 300 feet) have highest frequency winds generally from the southeast; and the wind directions which were the most persistent are from the southeast and south-southeast. These southeast and south-southeast persistent winds would direct any potential agricultural contamination away from the HVIs. Moreover, the BFN in scope HVIs have glazed insulation surfaces. As such, in accordance with the EPRI License Renewal Handbook, contamination buildup on insulators is not a problem due to rainfall periodically washing the insulators. TVA transmission design does allow the use of polymer type HVIs in selected circumstances, however, none of the HVIs in the BFN SBO path have polymer type (i.e., non-ceramic) insulators. Consequently, the rate of contamination buildup on high-voltage insulators at BFN is not significant.

Considering potential cooling tower plume contamination, the cooling towers at BFN are mechanical cooling towers located along the river. In scope HVIs are located just southeast of the cooling towers in the station transmission yard area. The nearest cooling tower, Cooling Tower 6, is approximately 550 feet to the nearest HVI (161 kV). The plume from the cooling towers poses no contamination risk to the in scope HVIs because the mechanical cooling towers, that are approximately 50 feet in height, dissipate the plumes quickly.

Additionally, TVA personnel conduct monthly and quarterly inspection tasks to help identify excessive HVI surface contamination. A search of operating experience for BFN HVIs was performed. Based on the results of this review, cumulative build up HVI contamination has not been experienced at BFN.

Considering potential foreign debris, the HVIs are located in rural area with no heavy industry or urban population centers.

With respect to surface contamination from fog, fog, in and of itself, is not a contaminant for HVIs. Therefore, surface contamination from fog is not an aging effect, is not subject to an aging management review, and does not require aging management.

Based on BFN Substation location, lack of substantial airborne contaminants, and its corroborating operating experience, excessive HVI surface contamination is not expected to occur. Therefore, aging effects of surface contamination from salt, dust, fog, cooling tower plume, foreign debris, and industrial effluents are not applicable to BFN for the subsequent period of extended operation. No aging management activity is required for the HVIs due to airborne contamination.

In addition, an evaluation was performed for cracking of porcelain. Porcelain cracking or breaking is most commonly caused by an object striking the HVI. Porcelain cracking has also occurred when cement that binds the parts together expands excessively. This phenomenon is known as cement growth; it occurs as a result of improper manufacturing that makes the cement more susceptible to moisture penetration. Plant specific operating experience associated with porcelain components of HVIs has been evaluated to determine if porcelain cracking due to cement growth has occurred at BFN. This evaluation did not identify any HVI porcelain cracking at BFN. HVI cracking caused by physical damage is not an aging effect evident at BFN. Therefore, BFN HVIs are not subject to an aging management review and do not require aging management.

<u>Loss of Material - Mechanical Wear or Corrosion</u>

Loss of material of HVIs can occur due to oscillating movement of transmission conductors due to significant and sustained winds. Significant wind can result in mechanical wear of metallic parts. Surface corrosion of HVI metallic parts can also occur due to environmental contamination or if galvanized or other protective coatings are worn from significant wind induced movement of transmission conductors.

Mechanical wear is an aging effect for strain insulators in that they are subject to movement. Movement can be caused by wind blowing the supported transmission conductor, causing it to swing. If this swinging is frequent enough, it could cause wear in the metal contact points of the insulator string.

The HVIs to be evaluated for aging effects due to movement of transmission conductors due to significant wind are those conductors with strain HVIs, which for BFN, only include the 161kV and the 500 kV voltage transmission conductors. The 161kV and the 500 kV strain type insulators support a short connection span of transmission conductors of three 2500 kcmil aluminum conductors that transition the incoming 500 kV lines to the aluminum bus network.

The TVA Transmission and Distribution design practices follow the NESC methodologies. The NESC sets the maximum tension of a conductor to withstand heavy load requirements which includes consideration of oscillating movement of transmission conductors due to significant wind. The TVA procedure uses a more conservative load rating than the NESC with regards to insulators.

Although this loss of material due to mechanical wear or corrosion of the metallic parts of HVIs is possible, experience has shown that the transmission conductors do not normally swing and that when they do, due to significant wind, they do not continue to swing for very long once the wind has subsided. Wind loading, that can cause a transmission line to sway, is considered and minimized during design and installation. The concerns for transmission conductor to swing is reduced for shorter spans. In addition, the installed configuration of the strain insulators minimizes movement. This reduces mechanical wear of metallic parts within the strain insulators such that these metallic contact points do not require inspection for mechanical wear.

Given TVA's transmission design conservatism exceeding the NESC and the lack of BFN specific operating experience to indicate mechanical wear, aging effects due to loss of material due to mechanical wear is not applicable to BFN for the subsequent period of extended operation.

Loss of material due to corrosion of HVIs can also occur due to airborne contamination. A large buildup of contamination could result in corrosion of the metallic parts of the HVIs, which if significant, could impact its structural intended function. As previously evaluated, based on the HVIs' location, lack of airborne contaminants, and its corroborating operating experience, HVI metallic parts are not subject to a large buildup of contamination from airborne contaminants. Therefore, these metallic contact points do not require inspection for corrosion.

HVI metallic part contamination induced corrosion is not a significant aging effect for BFN. Therefore, aging effects of surface contamination induced metallic parts corrosion are not applicable to BFN for the subsequent period of extended operation.

HVI metallic part aging due to wear from transmission conductor movement, airborne contamination, and surface rust are not significant aging concerns at BFN. A review of BFN operating experience has not identified significant corrosion or aging effects as the cause or failure mechanism of documented issues with HVIs. These aging effects are not significant at BFN and will not impact intended function of the HVIs during the subsequent period of extended operation. Therefore, aging effects of loss of material due to mechanical wear or corrosion are not applicable to BFN for the subsequent period of extended operation.

Operating Experience and Maintenance

The BFN substation and transmission components that are in scope for subsequent license renewal have normal maintenance tasks performed by TVA Transmission/Power Supply personnel on all portions of the switchyards, including insulators. Based on a review if the BFN operating experience, these maintenance activities have not revealed any aging effects/mechanisms associated with insulators.

Plant specific operating experience associated with porcelain components of HVIs has been evaluated to determine if porcelain cracking due to cement growth has occurred at BFN. Porcelain cracking has not been identified as a aging effect at BFN.

Plant specific operating experience associated with HVIs has been evaluated to determine if loss of metallic components or reduced insulation resistance has occurred at BFN. Loss of metallic components or reduced insulation resistance has not been identified as aging effects for HVIs at BFN.

<u>Conclusion</u>

Aging management activities for BFN HVIs are not required for the subsequent period of extended operation; therefore, the GALL-SLR report XI.E7, “High-Voltage Insulators” aging management program is not applicable to BFN.

3.6.2.4 Time-Limited Aging Analysis

The time-limited aging analysis identified below is associated with Electrical and I&C Commodities:

- Section 4.4, Environmental Qualification of Electric Equipment

3.6.3 Conclusion

The electrical commodities that are subject to aging management review have been identified in accordance with the requirements of 10 CFR 54.4. The aging management programs selected to manage aging effects for the electrical commodities are identified in the summaries in Section 3.6.2.1 above.

A description of these aging management programs is provided in Appendix B, along with the demonstration that the identified aging effects will be managed for the subsequent period of extended operation.

Therefore, based on the conclusions provided in Appendix B, the effects of aging associated with the electrical commodities will be adequately managed so that there is reasonable assurance that the intended functions are maintained consistent with the current licensing basis during the subsequent period of extended operation.

Table 3.6.1, Summary of Aging Management Evaluations for the Electrical Components

Item Number	Component	Aging Effect/ Mechanism	Aging ManagementPrograms	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	Environmental Qualification (EQ) is a TLAA; further evaluation is documented in Subsection 3.6.2.2.1. No electrical and I&C commodities within the EQ Program are subject to aging management review in accordance with the screening criteria of 10 CFR 54.21 (a)(1)(ii). However, the electrical and I&C commodities are managed in accordance with the EQ of Electric Equipment program (B.3.1.3).
3.6-1, 002	High-voltage electrical insulators composed of porcelain; malleable iron; aluminum; galvanized steel; cement; toughened glass; polymers; silicone rubber; fiberglass; aluminum alloy exposed to air – outdoor	Loss of material on metallic connectors due to mechanical wear or corrosion caused by movement of transmission conductors due to significant wind	AMP XI.E7, “High-Voltage Insulators”	No	Based on BFN design and operating experience, loss of material is not an applicable aging effect for high voltage electrical insulators in Electrical Commodities. In scope high voltage insulators comprised of porcelain; malleable iron; aluminum; galvanized steel; cement in an air - outdoor environment are not subject to loss of material due to mechanical wear or corrosion caused by movement of transmission conductors due to significant wind. See Subsection 3.6.2.3.1.

Table 3.6.1, Summary of Aging Management Evaluations for the Electrical Components (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging ManagementPrograms	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; fiberglass; aluminum alloy exposed to air – outdoor	Reduced electrical insulation resistance due to presence of cracks, foreign debris, salt, dust, cooling tower plume or industrial effluent contamination; peeling of silicone rubber sleeves for polymer insulators; or degradation of glazing on porcelain insulators	AMP XI.E7, 'High-Voltage Insulators"	No	Based on BFN geographic location, design, and operating experience, reduced insulation resistance is not an applicable aging effect for high voltage electrical insulators in Electrical Commodities. In scope high voltage electrical insulators comprised of porcelain; malleable iron; aluminum; galvanized steel; cement in an air - outdoor environment are not subject to reduced electrical insulation resistance due to presence of cracks, foreign debris, salt, dust, cooling tower plume, or industrial effluent contamination. See Subsection 3.6.2.3.1.
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	See Subsection 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	See Subsection 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	See Subsection 3.6.2.2.3.

Table 3.6.1, Summary of Aging Management Evaluations for the Electrical Components (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging ManagementPrograms	Further Evaluation Recommended	Discussion
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	See Subsection 3.6.2.2.3.
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. The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program (B.2.1.36) will be used to manage reduced electrical insulation resistance of the various organic polymers in electrical insulation for electrical cables and connections exposed to adverse localized environments.

Table 3.6.1, Summary of Aging Management Evaluations for the Electrical Components (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging ManagementPrograms	Further Evaluation Recommended	Discussion
3.6-1, 009	Electrical insulation for electrical cables and connections used in instrumentation circuits that are sensitive to reduction in conductor insulation resistance (IR) composed of various organic polymers (e.g., EPR, SR, EPDM, XLPE) exposed to an adverse localized environment caused by heat, radiation, or moisture	Reduced 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. The Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program (B.2.1.37) will be used to manage reduced electrical insulation resistance of the various organic polymers in electrical insulation for electrical cables and connections used in instrumentation circuits exposed to adverse localized environments.

Table 3.6.1, Summary of Aging Management Evaluations for the Electrical Components (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging ManagementPrograms	Further Evaluation Recommended	Discussion
3.6-1, 010	Electrical conductor insulation for inaccessible power, instrumentation, and control cables (e.g., installed in duct bank, buried conduit or direct buried) composed of various organic polymers such as EPR, SR, EPDM, XLPE, butyl rubber, and combined thermoplastic jacket/ insulation shield exposed to an adverse localized environment caused by significant moisture	Reduced electrical insulation resistance or degraded dielectric strength due to significant moisture	AMP XI.E3A, “Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements,” AMP XI.E3B, “Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements,” or AMP XI.E3C, “Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements”	No	Consistent with NUREG-2191. The Electrical Insulation for Inaccessible Medium Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program (B.2.1.38), Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program (B.2.1.39), and Electrical Insulation for Inaccessible Low Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program (B.2.1.40) will be used to manage reduced electrical insulation resistance or degraded dielectric strength of the various organic polymers in electrical conductor insulation for inaccessible medium voltage (>400 V to 35 kV) power, instrumentation and control, and low voltage (typically < 1 kV but no greater than 2 kV) cables exposed to adverse localized environments caused by significant moisture.
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	There are no metal enclosed bus enclosure assemblies composed of elastomers, exposed to air - indoor, controlled; air – indoor, uncontrolled; or air - outdoor.

Table 3.6.1, Summary of Aging Management Evaluations for the Electrical Components (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging ManagementPrograms	Further Evaluation Recommended	Discussion
3.6-1, 012	Metal enclosed bus: bus/ connections composed of various metals used for electrical bus and connections exposed to air – indoor controlled or uncontrolled, air – outdoor	Increased electrical resistance of connection due to the loosening of bolts caused by thermal cycling and ohmic heating	AMP XI.E4, “Metal Enclosed Bus”	No	Consistent with NUREG-2191. The Metal Enclosed Bus program (B.2.1.41) will be used to manage increased electrical resistance of connection of the various metals used for electrical bus and connections in metal enclosed bus exposed to air - indoor, controlled; air - indoor, uncontrolled; or air - outdoor.
3.6-1, 013	Metal enclosed bus: electrical insulation; insulators composed of porcelain; xenoy; thermo-plastic organic polymers exposed to air – indoor controlled or uncontrolled, air – outdoor	Reduced electrical insulation resistance due to thermal/ thermoxidative degradation of organics/ thermoplastics, radiation-induced oxidation, moisture/ debris intrusion, and ohmic heating	AMP XI.E4, “Metal Enclosed Bus”	No	Consistent with NUREG-2191. The Metal Enclosed Bus program (B.2.1.41) will be used to manage reduced electrical insulation resistance of the porcelain and various organic polymers in metal enclosed bus: electrical Insulation, electrical insulators exposed to air - indoor, controlled; air - indoor, uncontrolled; or air - outdoor.

Table 3.6.1, Summary of Aging Management Evaluations for the Electrical Components (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging ManagementPrograms	Further Evaluation Recommended	Discussion
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	There are no steel metal enclosed bus, external surfaces of enclosure assemblies, exposed to air-indoor, uncontrolled, air - outdoor environments in BFN Electrical Commodities.
3.6-1, 015	Metal enclosed bus: external surface of enclosure assemblies composed of galvanized steel; aluminum exposed to air – outdoor	Loss of material due to pitting, crevice corrosion	AMP XI.E4, "Metal Enclosed Bus," or AMP XI.S6" "Structures Monitoring"	No	Consistent with NUREG-2191. The Metal Enclosed Bus program (B.2.1.41) will be used to manage loss of material of the galvanized steel or aluminum metal enclosed bus: external surface of enclosure assemblies exposed to air - outdoor.
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. The Fuse Holder program (B.2.1.42) will be used to manage increased electrical resistance of metallic clamps of fuse holders exposed to air - indoor, uncontrolled.

Table 3.6.1, Summary of Aging Management Evaluations for the Electrical Components (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging ManagementPrograms	Further Evaluation Recommended	Discussion
3.6-1, 017	Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air- indoor controlled or uncontrolled	Increased electrical resistance of connection due to fatigue from ohmic heating, thermal cycling, electrical transients	AMP XI.E5, “Fuse Holders” No aging management program is required for those applicants who can demonstrate these fuse holders are not subject to fatigue due to ohmic heating, thermal cycling, electrical transients	No	Consistent with NUREG-2191. The Fuse Holder program (B.2.1.42) will be used to manage increased electrical resistance of metallic clamps of fuse holders exposed to air - indoor, controlled or uncontrolled.
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. The Fuse Holder program (B.2.1.42) will be used to manage increased electrical resistance of metallic clamps of fuse holders expose to air - indoor, controlled or uncontrolled.
3.6-1, 019	Cable connections (metallic parts) composed of various metals used for electrical contacts exposed to air – indoor controlled or uncontrolled, air – outdoor	Increased electrical resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation	AMP XI.E6, “Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements”	No	Consistent with NUREG-2191. The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program (B.2.1.43) will be used to manage increased electrical resistance of connection of the various metals used for electrical contacts cable connections (metallic parts) exposed to air-indoor, controlled; air - indoor, uncontrolled; or air - outdoor in BFN Electrical Commodities.
3.6-1, 020	PWR Only				

Table 3.6.1, Summary of Aging Management Evaluations for the Electrical Components (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging ManagementPrograms	Further Evaluation Recommended	Discussion
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	There are no aging effects to be managed for all aluminum transmission conductors exposed to air - outdoor environments in BFN Electrical Commodities. See Subsection 3.6.2.2.3.
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. The Fuse Holder program (B.2.1.42) will be used to manage reduced electrical insulation resistance of electrical insulation material of fuse holders exposed to air - indoor, controlled or uncontrolled.
3.6-1, 023	Metal enclosed bus: external surface of enclosure assemblies. Galvanized steel; aluminum. air – indoor controlled or uncontrolled	None	None	No	There are no aging effects to be managed for galvanized steel or aluminum metal enclosed bus, external surfaces of enclosure assemblies, exposed to air - indoor, controlled or air - indoor, uncontrolled environments in BFN Electrical Commodities.
3.6-1, 024	Metal enclosed bus: external surface of enclosure assemblies. Steel. air – indoor controlled	None	None	No	There are no steel metal enclosed bus, external surfaces of enclosure assemblies, exposed to air - indoor, controlled environments in BFN Electrical Commodities.
3.6-1, 025	This Item Number is not listed in NUREG-2192.				

Table 3.6.1, Summary of Aging Management Evaluations for the Electrical Components (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging ManagementPrograms	Further Evaluation Recommended	Discussion
3.6-1, 026	This Item Number is not listed in NUREG-2192.				
3.6-1, 027	Cable bus: external surface of enclosure assemblies. Galvanized steel; aluminum; air – indoor controlled or uncontrolled	None	None	No	There are no galvanized steel or aluminum cable bus, external surfaces of enclosure assemblies, exposed to air - indoor, controlled or air - indoor, uncontrolled, environments in Electrical Commodities. See Subsection 3.6.2.2.2.
3.6-1, 028	This Item Number is not listed in NUREG-2192.				
3.6-1, 029	Cable bus: electrical insulation; insulators – exposed to air – indoor controlled or uncontrolled, air – outdoor	Reduced electrical insulation resistance due to degradation caused thermal/ thermoxidative degradation of organics and photolysis (UV sensitive materials only) of organics, moisture/debris intrusion and ohmic heating	A plant-specific aging management program is to be evaluated	Yes	There are no cable bus, electrical insulation and insulators, exposed to air - indoor, controlled; air - indoor, uncontrolled; or air - outdoor in Electrical Commodities. See Subsection 3.6.2.2.2.
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	There are no cable bus, external surface of enclosure assemblies, composed of steel, exposed to air - indoor, uncontrolled or air - outdoor in Electrical Commodities. See Subsection 3.6.2.2.2.

Table 3.6.1, Summary of Aging Management Evaluations for the Electrical Components (Continued)

Item Number	Component	Aging Effect/ Mechanism	Aging ManagementPrograms	Further Evaluation Recommended	Discussion
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	There are no cable bus, external surface of enclosure assemblies, composed of galvanized steel or aluminum; exposed to air - outdoor in Electrical Commodities. See Subsection 3.6.2.2.2.
3.6-1, 032	Cable bus: external surface of enclosure assemblies: composed of steel; air - indoor controlled	None	None	No	There are no cable bus, external surface of enclosure assemblies, composed of steel exposed to air - indoor, controlled in Electrical Commodities. See Subsection 3.6.2.2.2.

Table 3.6.2-1, Electrical and I&C Commodities - Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Cable Connections (Metallic Parts)	Electrical Continuity	Various Metals Used for Electrical Contacts	Air - Indoor, Controlled or Uncontrolled, or Air - Outdoor	Increased Electrical Resistance of Connection	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.43)	VI.A.LP-30	3.6-1, 019	A
Electric Equipment Subject to 10 CFR 50.49 EQ Requirements	Electrical Continuity	Various Metallic Materials	10 CFR 50.49 EQ Environments	Various Aging Effects	Environmental Qualification of Electric Equipment (B.3.1.3)	VI.B.L-05	3.6-1, 001	A
Electric Equipment Subject to 10 CFR 50.49 EQ Requirements	Electrical Continuity	Various Metallic Materials	Adverse Localized Environment	Various Aging Effects	Environmental Qualification of Electric Equipment (B.3.1.3)	VI.B.L-05	3.6-1, 001	A
Electric Equipment Subject to 10 CFR 50.49 EQ Requirements	Insulate (Electrical)	Various Polymeric Materials	10 CFR 50.49 EQ Environments	Various Aging Effects	Environmental Qualification of Electric Equipment (B.3.1.3)	VI.B.L-05	3.6-1, 001	A
Electric Equipment Subject to 10 CFR 50.49 EQ Requirements	Insulate (Electrical)	Various Polymeric Materials	Adverse Localized Environment	Various Aging Effects	Environmental Qualification of Electric Equipment (B.3.1.3)	VI.B.L-05	3.6-1, 001	A
Electrical Insulation for Electrical Cables and Connections	Insulate (Electrical)	Various Organic Polymers	Adverse Localized Environment	Reduced Electrical Insulation Resistance	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.36)	VI.A.LP-33	3.6-1, 008	A

Table 3.6.2-1, Electrical and I&C Commodities - Summary of Aging Management Evaluation (Continued)								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**NUREG-2192 Table 1 Item**	**Notes**
Electrical Insulation for Electrical Cables and Connections used in Instrumentation Circuits	Insulate (Electrical)	Various Organic Polymers	Adverse Localized Environment	Reduced Electrical Insulation Resistance	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (B.2.1.37)	VI.A.LP-34	3.6-1, 009	A
Electrical conductor insulation for inaccessible medium-voltage cables - typical operating range of 400 v to 35 kV	Insulate (Electrical)	Various Organic Polymers	Adverse Localized Environment Caused by Significant Moisture	Reduced electrical insulation resistance or degraded dielectric strength	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.38)	VI.A.LP-35a	3.6-1, 010	A
Electrical conductor insulation for inaccessible instrumentation and control cables	Insulate (Electrical)	Various Organic Polymers	Adverse Localized Environment Caused by Significant Moisture	Reduced electrical insulation resistance or degraded dielectric strength	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.39)	VI.A.LP-35b	3.6-1, 010	A
Electrical conductor insulation for inaccessible low - voltage cables - typical operating voltage of < 1 kV but no greater than 2 kV	Insulate (Electrical)	Various Organic Polymers	Adverse Localized Environment Caused by Significant Moisture	Reduced electrical insulation resistance or degraded dielectric strength	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.40)	VI.A.LP-35c	3.6-1, 010	A

Table 3.6.2-1, Electrical and I&C Commodities - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Fuse Holders (not part of active equipment): Metallic Clamps	Electrical Continuity	Various Metals Used for Electrical Connections	Air - Indoor Uncontrolled	Increased electrical resistance of connection (for Metallic Clamps)	Fuse Holders (B.2.1.42)	VI.A.LP-23	3.6-1, 016	A
Fuse Holders (not part of active equipment): Metallic Clamps	Electrical Continuity	Various Metals Used for Electrical Connections	Air - Indoor, Controlled or Uncontrolled	Increased electrical resistance of connection (for Metallic Clamps)	Fuse Holders (B.2.1.42)	VI.A.L-07	3.6-1, 017	A
Fuse Holders (not part of active equipment): Metallic Clamps	Electrical Continuity	Various Metals Used for Electrical Connections	Air - Indoor, Controlled or Uncontrolled	Increased electrical resistance of connection (for Metallic Clamps)	Fuse Holders (B.2.1.42)	VI.A.LP-31	3.6-1, 018	A
Fuse Holders (not part of active equipment): Electrical Insulation	Insulate (Electrical)	Electrical Insulation: Bakelite; Phenolic Melamine or Ceramic; Molded Polycarbonate; Other	Air - Indoor, Controlled or Uncontrolled	Reduced electrical insulation resistance (for Insulation Materials)	Fuse Holders (B.2.1.42)	VI.A.LP-24	3.6-1, 022	A
High Voltage Electrical Insulators	Insulate (Electrical)	Porcelain; Malleable Iron; Aluminum; Galvanized Steel; Cement	Air - Outdoor	None	None	VI.A.LP-32	3.6-1, 002	I, 1
High Voltage Electrical Insulators	Insulate (Electrical)	Porcelain; Malleable Iron; Aluminum; Galvanized Steel; Cement	Air - Outdoor	None	None	VI.A.LP-28	3.6-1, 003	I, 2

Table 3.6.2-1, Electrical and I&C Commodities - Summary of Aging Management Evaluation (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	NUREG-2192 Table 1 Item	Notes
Metal Enclosed Bus: Bus/Connections	Electrical Continuity	Various Metals Used for Electrical Bus and Connections	Air - Indoor, Controlled or Uncontrolled, or Air - Outdoor	Increased Electrical Resistance of Connection	Metal Enclosed Bus (B.2.1.41)	VI.A.LP-25	3.6-1, 012	A
Metal Enclosed Bus: Electrical Insulation, Electrical Insulators	Insulate (Electrical)	Porcelain; Xenoy; Thermo-Plastic Organic Polymers	Air - Indoor, Controlled or Uncontrolled, or Air - Outdoor	Reduced Electrical Insulation Resistance	Metal Enclosed Bus (B.2.1.41)	VI.A.LP-26	3.6-1, 013	A
Metal Enclosed Bus: External Surface of Enclosure Assemblies	Shelter Protection	Galvanized Steel; Aluminum	Air - Outdoor	Loss of Material	Metal Enclosed Bus (B.2.1.41)	VI.A.LP-42	3.6-1, 015	A
Metal Enclosed Bus: External Surface of Enclosure Assemblies	Shelter Protection	Galvanized Steel; Aluminum	Air - Indoor, Controlled or Uncontrolled	None	None	VI.A.LP-41	3.6-1, 023	A
Switchyard Bus and Connections	Electrical Continuity	Aluminum, Stainless Steel, Copper, Bronze, Galvanized Steel	Air - Outdoor	None	None	VI.A.LP-39	3.6-1, 006	I, 3
Transmission Conductors	Electrical Continuity	Aluminum, Steel	Air - Outdoor	None	None	VI.A.LP-38	3.6-1, 004	I, 5
Transmission Conductors	Electrical Continuity	Aluminum, Steel	Air - Outdoor	None	None	VI.A.LP-47	3.6-1, 007	I, 6
Transmission Conductors	Electrical Continuity	Aluminum	Air - Outdoor	None	None	VI.A.LP-46	3.6-1, 021	I, 4
Transmission Connectors	Electrical Continuity	Aluminum, Steel	Air - Outdoor	None	None	VI.A.LP-48	3.6-1, 005	I, 7

Table 3.6.2-1 Notes

Generic Notes

A. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
B. Consistent with component, material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
C. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP.
D. Component is different, but consistent with material, environment, aging effect and aging management program listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP.
E. Consistent with NUREG-2191 material, environment, and aging effect but a different aging management program is credited or NUREG-2191 identifies a plant-specific aging management program.
F. Material not in NUREG-2191 for this component.
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.

Plant Specific Notes

1. Based on BFN design and operating experience, loss of material is not an applicable aging effect for BFN high-voltage electrical insulators. In scope high-voltage electrical insulators comprised of porcelain, malleable iron, aluminum, galvanized steel, cement exposed to an air - outdoor environment are not subject to mechanical wear caused by wind blowing on transmission conductors transients. See Subsection 3.6.2.3.1 for additional information.
2. Based on BFN design and operating experience, reduced electrical insulation resistance is not an applicable aging effect for BFN high-voltage electrical insulators. In scope high-voltage electrical insulators comprised of porcelain, malleable iron, aluminum, galvanized steel, cement exposed to an air - outdoor environment are not subject to reduced electrical insulation resistance due to presence of cracks, foreign debris, salt, dust, cooling tower plume, or industrial effluent contamination; peeling of silicone rubber sleeves for polymer insulators; or degradation of glazing on porcelain insulators. See Subsection 3.6.2.3.1 for additional information.
3. Based on BFN design and operating experience, loss of material due to wind-induced abrasion; Increased electrical resistance of connection due to oxidation or loss of pre-load are not applicable aging effects for BFN switchyard bus and connections. In scope switchyard bus and connections

comprised of aluminum, copper, bronze, stainless steel and galvanized steel in an air - outdoor environment are not subject to wind induced abrasion nor oxidation or loss of pre-load. See Subsection 3.6.2.2.3 for additional information.

4. Based on SRP-SLR Table 3.6-1 Item 021 and BFN design and operating experience, loss of conductor strength due to corrosion is not applicable for ACAR and All Aluminum Conductor (AAC). This line item is consistent with NUREG-2191.
5. Based on BFN design and operating experience, loss of conductor strength due to corrosion is not an applicable aging effect for BFN ACSR transmission conductors. In scope BFN transmission conductors comprised of aluminum and steel in an air - outdoor environment are not subject to wind induced abrasion. See Subsection 3.6.2.2.3 for additional information.
6. Based on BFN design and operating experience, loss of conductor strength is not an applicable aging effect for BFN ACSR transmission conductors. In scope BFN transmission conductors comprised of aluminum and steel in an air - outdoor environment are not subject to corrosion. See Subsection 3.6.2.2.3 for additional information.
7. Based on BFN design and operating experience, increased resistance of connection is not an applicable aging effect for BFN transmission connectors. In scope BFN transmission connectors comprised of stainless steel in an air - outdoor environment are not subject to oxidation or loss of pre-load. See Subsection 3.6.2.2.3 for additional information.

4.0 TIME-LIMITED AGING ANALYSES

This is a non-proprietary version of Section 4, which has the proprietary information removed. Portions of Section 4 that have been removed are indicated by a set of open and closed double bold brackets as shown here **{{ }}**.

4.1 IDENTIFICATION AND EVALUATION OF TIME-LIMITED AGING ANALYSES (TLAAs)

Pursuant to 10 CFR 54.3, time-limited aging analyses (TLAAs) are those licensee calculations and analyses that:

1. Involve systems, structures, and components within the scope of license renewal as delineated in 10 CFR 54.4(a);
2. Consider the effects of aging;
3. Involve time-limited assumptions defined by the current operating term, for example, 40 years;
4. Were determined to be relevant by the licensee in making a safety determination;
5. Involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions as delineated in 10 CFR 54.4(b); and
6. Are contained or incorporated by reference in the current licensing basis (CLB).

4.1.1 Identification of BFN Time-Limited Aging Analyses

TLAAs have been identified for BFN using methods consistent with those provided in 10 CFR 54, Requirements for Renewal of Operating Licenses for Nuclear Power Plants (Reference 4.8.1) and NUREG-2192, Revision 0, Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (Reference 4.8.2).

Each potential TLAA was reviewed against the six criteria from 10 CFR 54.3(a) listed in Section 4.1 above. Those that meet all six criteria were identified as TLAAs that require evaluation for the subsequent period of extended operation. While the current license term referred to in 10 CFR 54.3 is now 60 years for BFN, all TLAAs that were identified in the initial License Renewal Application (LRA), based on a 40-year term, have been identified and evaluated.

A list of potential generic TLAAs was assembled from the SRP, industry guidance and experience, including:

- NUREG-2191, Revision 0, Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report (Reference 4.8.3)
- NUREG-2192, Revision 0, Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (Reference 4.8.2)
- Nuclear Energy Institute (NEI) 95-10, Revision 6, Industry Guideline for Implementing the Requirements of 10 CFR 54, the License Renewal Rule (Reference 4.8.4)
- NEI 17-01, Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal, March 2017 (Reference 4.8.5)
- The 10 CFR 54 Final Rule, Statement of Considerations
- Prior license renewal applications, NRC Requests for Additional Information, and NRC Safety Evaluation Reports for these applications.

BFN CLB and design basis documentation were searched to identify potential TLAAs. The document search included the following:

- Final Safety Analysis Report (FSAR)
- Renewed Facility Operating Licenses and License Conditions
- Technical Specifications, Bases, and Technical Requirements Manual
- Docketed Licensing Correspondence, including those associated with the initial LRA.
- NRC Safety Evaluation Reports (SERs) and Safety Evaluations (SEs)
- Design Criteria Documents (DCDs)
- Design Specifications, Calculations and Reports incorporated by reference in CLB
- Environmental Qualification Documentation Packages
- Engineering Change Requests
- Corrective Action Program Reports
- Exemptions granted pursuant to 10 CFR 50.12
- Inservice Inspection Relief Requests

4.1.2 Evaluation of BFN Time-Limited Aging Analyses

Each BFN TLAA has been evaluated for the subsequent period of extended operation. Each evaluation contains the following information:

TLAA Description

A description of the CLB analysis that has been identified as a TLAA, including a description of the aging effect evaluated, the time-limited variable used in the analysis, and its basis.

TLAA Evaluation

An evaluation of the TLAA for the subsequent period of extended operation. This section provides information associated with 80 years of operation for comparison with the information used in the TLAA that considered the previous license term of operation. This evaluation provides the basis for the disposition, which falls into one of the three disposition categories described below.

TLAA Disposition

The disposition is classified in accordance with one of the acceptance criteria from 10 CFR 54.21(c)(1) specified below in Section 4.1.3.

4.1.3 Acceptance Criteria

10 CFR 54.21, Contents of application - technical information, states 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 §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 for the subsequent period of extended operation for BFN. The methods used are identified in each TLAA evaluation section.

4.1.4 Summary of Results

SLRA Table 4.1-1 lists the example TLAAs provided in NUREG-2192, Tables 4.1-2 and 4.7-1, and specifies whether or not they have been identified as TLAAs for BFN. Those examples with a “Yes” entry apply for BFN and the section(s) where the TLAA(s) are evaluated are provided. Those examples with a “No” entry do not apply for BFN and no TLAA was identified for these categories either because they are associated with design features not employed at BFN or because no analysis was identified that meet all six TLAA criteria.

SLRA Table 4.1-2 is a summary of the TLAAs identified for BFN. The TLAAs are grouped by affected component and aging effect analyzed. The table entries also state the disposition method used in evaluating the TLAA and include a reference to the applicable SLRA section where the TLAA is evaluated for the subsequent period of extended operation.

4.1.5 Identification of Exemptions Pursuant to 10 CFR 50.12

10 CFR 54.21(c)(2) states that for TLAA exemptions, a list must be provided of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on time-limited aging analyses as defined in 10 CFR 54.3. The applicant shall provide an evaluation that justifies the continuation of these exemptions for the period of extended operation.

Exemptions pursuant to 10 CFR 50.12 currently in effect for BFN Unit 1, BFN Unit 2, and BFN Unit 3 were reviewed to determine if they are based upon a TLAA. 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.

Table 4.1-1, Review of Generic TLAAs Listed in NUREG-2192, Tables 4.1-2 and 4.7-1

NUREG-2192, Table 4.1-2 - Generic TLAAs		
NUREG-2192 Examples of Potential Generic and Plant-Specific TLAAs	Applies for BFN	SLRA Section
Neutron Fluence	Yes	4.2.1
Pressurized Thermal Shock (PWRs Only)	No	N/A
Upper-Shelf Energy (PWRs and BWRs)	Yes	4.2.2
Pressure Temperature (P-T) Limits (PWRs and BWRs)	Yes	4.2.4
Low Temperature Overpressure Protection System Setpoints (PWRs Only)	No	N/A
Ductility Reduction Evaluation for Reactor Internals (B&W designed PWRs only)	No	N/A
RPV Circumferential Weld Relief-Probability of Failure and Mean Adjusted Reference Temperature Analysis for the RPV Circumferential Welds (BWRs only)	Yes	4.2.5
Reactor Vessel Axial Weld Probability of Failure and Mean Adjusted Reference Temperature Analysis (BWRs only)	Yes	4.2.6
Metal Fatigue of Class 1 Components	Yes	4.3.2,4.3.3
Metal Fatigue of Non-Class 1 Components	Yes	4.3.4
Environmentally-Assisted Fatigue	Yes	4.3.5
High Energy Line Break Analyses	No[1]	N/A
Cycle-dependent Fracture Mechanics or Flaw Evaluations	Yes	4.3.7
Cycle-dependent Fatigue Waivers	Yes	4.3.3
Environmental Qualification of Electric Equipment	Yes	4.4.1
Concrete Containment Tendon Prestress	No[2]	N/A
Containment Liner Plate, Metal Containments, and Penetrations Fatigue	Yes	4.6

Table 4.1-1, Review of Generic TLAAs Listed in NUREG-2192, Tables 4.1-2 and 4.7-1 (Continued)

NUREG-2192, Table 4.7-1 - Examples of Potential Plant-Specific TLAA Topics (BWRs)		
NUREG-2192 Examples of Potential Generic and Plant-Specific TLAAs	Applies for BFN	SLRA Section
Reflood Thermal Shock of the Reactor Pressure Vessel	Yes	4.2.7
Reflood Thermal Shock of the Core Shroud and Other Reactor Vessel Internals	Yes	4.2.8
Loss of Preload for Core Plate Rim Hold-Down Bolts	Yes	4.2.9
Erosion of the Main Steam Line Flow Restrictors	No[1]	N/A
Susceptibility to Irradiation-Assisted Stress Corrosion Cracking	Yes	4.2.14
Fatigue of Cranes (Crane Cycle Limits)	Yes	4.7.1
Fatigue of the Spent Fuel Pool Liner	No[1]	N/A
Corrosion Allowance Calculations	No[1]	N/A
Flaw Growth due to Stress Corrosion Cracking	No[1]	N/A
Predicted Lower Limit	No[1]	N/A

Notes:

1. There are no CLB analysis containing time-based assumptions as defined in 10 CFR 54.3(a)
2. The BFN containment does not contain prestressed concrete tendons.

Table 4.1-2, Summary of Results - BFN Time-Limited Aging Analyses

TLAA Description	Disposition	SLRA Section
Identification and Evaluation of Time-Limited Aging Analyses (TLAAs)		4.1
Identification of BFN Time-Limited Aging Analyses		4.1.1
Evaluation of BFN Time-Limited Aging Analyses		4.1.2
Acceptance Criteria		4.1.3
Summary of Results		4.1.4
Identification of Exemptions Pursuant to 10 CFR 50.12		4.1.5
Reactor Vessel and Internals Neutron Embrittlement Analyses		4.2
Reactor Vessel Neutron Fluence Analyses	§54.21(c)(1)(ii)	4.2.1.1
Reactor Vessel Internals Neutron Fluence Analyses	§54.21(c)(1)(ii)	4.2.1.2
Reactor Vessel Upper-Shelf Energy (USE) Analyses	§54.21(c)(1)(ii)	4.2.2
Reactor Vessel Adjusted Reference Temperature (ART) Analyses	§54.21(c)(1)(ii)	4.2.3
Reactor Vessel Pressure-Temperature (P-T) Limits	§54.21(c)(1)(iii)	4.2.4
Reactor Vessel Circumferential Weld Failure Probability Analyses	§54.21(c)(1)(iii)	4.2.5
Reactor Vessel Axial Weld Failure Probability Analyses	§54.21(c)(1)(ii)	4.2.6
Reactor Vessel Reflood Thermal Shock Analysis	§54.21(c)(1)(ii)	4.2.7
Core Shroud Reflood Thermal Shock Analysis	§54.21(c)(1)(ii)	4.2.8
Core Plate Hold-Down Bolt Loss of Preload Analysis	§54.21(c)(1)(ii)	4.2.9
Jet Pump Slip Joint Repair Clamp Loss of Preload Analysis	§54.21(c)(1)(ii)	4.2.10
Jet Pump Auxiliary Spring Wedge Assembly Loss of Preload Analysis	§54.21(c)(1)(i)	4.2.11
Jet Pump Riser Repair Clamp Loss of Preload Analysis	§54.21(c)(1)(i)	4.2.12
Replacement Core Support Plate Plug Extended Life Irradiation -Enhanced Stress Relaxation Analysis	§54.21(c)(1)(ii)	4.2.13
Irradiation Assisted Stress Corrosion Cracking (IASCC) of Reactor Vessel Internals	§54.21(c)(1)(iii)	4.2.14
Core Spray Replacement Piping Bolting Loss of Preload Evaluation	§54.21(c)(1)(i)	4.2.15
Core Spray Sparger Repair Clamp Loss of Preload Evaluation	§54.21(c)(1)(ii)	4.2.16
Access Hole Cover Repair Loss of Preload Evaluation	§54.21(c)(1)(i)	4.2.17
Jet Pump Hold-Down Beam Assembly Loss of Preload Analysis	§54.21(c)(1)(ii)	4.2.18

Table 4.1-2, Summary of Results - BFN Time-Limited Aging Analyses (Continued)

TLAA Description	Disposition	SLRA Section
Jet Pump Sensing Line Clamps Loss of Preload Analysis	§54.21(c)(1)(i)	4.2.19
Metal Fatigue Analyses		4.3
Metal Fatigue of Class 1 Components	§54.21(c)(1)(iii)	4.3.2
Class 1 Fatigue Waivers	§54.21(c)(1)(ii)	4.3.3
Metal Fatigue of Non-Class 1 Components	§54.21(c)(1)(i)	4.3.4
Environmental Fatigue Analyses for Reactor Vessel and Class 1 Piping	§54.21(c)(1)(iii)	4.3.5
Replacement Steam Dryer Stress Report and Fatigue Evaluation	§54.21(c)(1)(i)	4.3.6
Emergency Equipment Cooling Water Weld Flaws Evaluation	§54.21(c)(1)(ii)	4.3.7
Core Shroud Support Fatigue Analysis	§54.21(c)(1)(ii)	4.3.8
BFN Unit 3 Core Spray T-Box Repair Fatigue Evaluation	§54.21(c)(1)(iii)	4.3.9
BFN Unit 3 Core Spray Lower Line Section Replacement Fatigue Evaluation	§54.21(c)(1)(iii)	4.3.10
Jet Pump to Core Shroud Support Plate Fatigue Evaluation	§54.21(c)(1)(iii)	4.3.11
Environmental Qualification Of Electric Equipment		4.4
Environmental Qualification of Electric Equipment	§54.21(c)(1)(iii)	4.4.1
Concrete Containment Tendon Prestress Analysis		4.5
Concrete Containment Tendon Prestress Analysis	N/A	4.5
Primary Containment Fatigue Analyses		4.6
Suppression Chambers, Vents and Downcomers	§54.21(c)(1)(iii)	4.6.1
Torus Attached Piping and Safety Relief Valve Discharge Lines	§54.21(c)(1)(i)	4.6.2
Containment Vent Lines and Process Penetration Bellows	§54.21(c)(1)(i)	4.6.3
Other Plant-Specific Analyses		4.7
Reactor Building Crane Cyclic Loading	§54.21(c)(1)(i)	4.7.1
Radiation Degradation of Drywell Expansion Gap Foam	§54.21(c)(1)(ii)	4.7.2
BFN Unit 2 Reactor Vessel Axial Weld Flaw	§54.21(c)(1)(iii)	4.7.3

4.2 REACTOR VESSEL AND INTERNALS NEUTRON EMBRITTLEMENT ANALYSES

Reactor Vessel Embrittlement TLAAs

10 CFR 50.60 (Reference 4.8.7) requires that all light-water reactors meet the fracture toughness, P-T limits, and material surveillance program requirements for the reactor coolant pressure boundary as set forth in 10 CFR 50, Appendices G and H (References 4.8.8 and 4.8.9). The ferritic materials of the reactor vessel are subject to embrittlement due to high energy (E > 1.0 million electron volts (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 cumulative neutron fluence (total number of neutrons that intersect a square centimeter of component area during the life of the plant) (Reference 4.8.53).

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 (Reference 4.8.54). Neutron embrittlement results in a decrease in the USE of reactor vessel steels (Reference 4.8.27). This means greater temperatures are required for the material to behave in a ductile manner.

To reduce the potential for brittle fracture during reactor vessel operation, changes in material toughness as a function of neutron radiation exposure (fluence) are accounted for through the use of operating pressure-temperature (P-T) limits that are managed in accordance with the BFN Units 1, 2 and 3 Technical Specifications. The P-T limits account for the decrease in material toughness of the reactor vessel beltline materials associated with a given fluence. P-T limit curves are generated to provide minimum temperature limits that must be achieved during operations prior to application of specified reactor vessel pressures. The P-T limit curves are based, in part, upon Adjusted Reference Temperature (ART) values for each material located within the beltline region of the reactor vessel. The ART value is computed using the initial RT_{NDT} (nil-ductility temperature) and ΔRT_{NDT} (change in nil-ductility temperature due to fluence) computed for the licensed operating period, along with appropriate margins (Reference 4.8.55).

The beltline region includes the reactor vessel plates, welds and forging materials (Reference 4.8.8) that are predicted to receive a cumulative neutron exposure of 1.0E+17 neutrons/cm^2 through the end of the subsequent period of extended operation. Since the cumulative neutron fluence will increase during the subsequent period of extended operation, a review is required to determine if any additional components will exceed the threshold value and require evaluation for neutron embrittlement.

Based on the projected drop in toughness for each beltline material as a result of exposure to the predicted fluence values, USE calculations are performed to determine if the components will continue to have adequate fracture toughness at the end of license to meet the required minimums. Where the USE value for beltline materials does not meet the required minimum value, an Equivalent Margins Analysis is performed. The reactor vessel material ART and USE values, calculated on the basis of neutron fluence, as well as the P-T limit curves based on the ART values, are part of the licensing basis and support safety determinations and therefore have been identified as TLAAs. The increases in RT_{NDT} (ΔRT_{NDT}) also affect the bases for relief from circumferential weld inspection and the supporting calculation of limiting axial weld conditional failure probability. Therefore, these calculations have been identified as TLAAs. A reflood thermal shock analysis for the reactor vessel has been also identified that is based upon irradiated material properties derived using neutron fluence values as inputs. Therefore, these analyses have been identified as TLAAs.

The following TLAAs related to neutron embrittlement of the reactor vessel are evaluated in the SLRA subsections listed below:

- Reactor Vessel Neutron Fluence Analyses (Section 4.2.1.1)
- Reactor Vessel Upper-Shelf Energy (USE) Analyses (Section 4.2.2)
- Reactor Vessel Adjusted Reference Temperature (ART) Analyses (Section 4.2.3)
- Reactor Vessel Pressure-Temperature (P-T) Limits (Section 4.2.4)
- Reactor Vessel Circumferential Weld Failure Probability Analyses (Section 4.2.5)
- Reactor Vessel Axial Weld Failure Probability Analyses (Section 4.2.6)
- Reactor Vessel Reflood Thermal Shock Analysis (Section 4.2.7)

<u>RV Internal Component TLAAs</u>

Several reactor vessel internal components, including core plate hold-down bolts, have been analyzed for loss of preload due to irradiation-enhanced stress relaxation due to neutron fluence and other aging mechanisms. These have also been identified as TLAAs that are evaluated in the SLRA subsections listed below:

- Reactor Vessel Internals Neutron Fluence Analyses (Section 4.2.1.2)
- Core Shroud Reflood Thermal Shock Analysis (Section 4.2.8)
- Core Plate Hold-down Bolt Loss of Preload Analysis (Section 4.2.9)
- Jet Pump Slip Joint Clamp Loss of Preload Analysis (Section 4.2.10)
- Jet Pump Auxiliary Spring Wedge Assembly Loss of Preload Analysis (Section 4.2.11)
- Jet Pump Riser Repair Clamp Loss of Preload Analysis (Section 4.2.12)
- Replacement Core Plate Plug Extended Life Irradiation -Enhanced Stress Relaxation Analysis (Section 4.2.13)
- Irradiation Assisted Stress Corrosion Cracking (IASCC) of Reactor Vessel Internals (Section 4.2.14)
- Core Spray Replacement Piping Bolting Loss of Preload Evaluation (Section 4.2.15)
- Core Spray Sparger Repair Clamp Loss of Preload Evaluation (Section 4.2.16)
- Access Hole Cover Repair Loss of Preload Evaluation (Section 4.2.17)
- Jet Pump Hold-Down Beam Assembly Loss of Preload Analysis (Section 4.2.18)
- Jet Pump Sensing Line Clamps Loss of Preload Analysis (Section 4.2.19)

The reactor vessel internals neutron embrittlement TLAAs listed above have been evaluated, as described in Sections 4.2.8 through 4.2.19, based upon 80-year fluence projections described in Section 4.2.1.2.

4.2.1 Reactor Vessel and Internals Neutron Fluence Analyses

Neutron fluence is the term used to represent the cumulative number of neutrons per square centimeter (flux) that contact the reactor vessel shell and its internal components over a given period of time. 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 loss of fracture toughness aging effect resulting from neutron fluence.

The NRC approved General Electric Hitachi (GEH) Discrete Ordinates Transfer (DORT) methodology was used in developing the 60-year fluence projections (Reference 4.8.11) and associated reactor vessel embrittlement analyses that account for an Extended Power Uprate (EPU) and Maximum Extended Load Line Limit Analysis Plus (MELLLA+) operating strategy (Reference 4.8.13).

The current uprated power level of 3952 megawatts thermal (MWt) is the maximum power level evaluated for the subsequent period of extended operation. Eighty-year fluence projections for the BFN vessels are used in evaluating the neutron embrittlement TLAAs in Sections 4.2.2 through 4.2.7. TransWare Radiation Analysis Modeling Application (RAMA) methodology has been used to develop 80-year fluence projections for reactor vessel internal components that are used in evaluating reactor vessel internal component TLAAs in Sections 4.2.1.2 and 4.2.8 through 4.2.15. The basis for acceptability of each of these fluence projection methods is described in the applicable sections below. There has been no combination of the two methodologies applied to any component.

<u>BFN Power Level Background</u>

Below is a summary BFN historical operating power levels which have been considered in developing the 80-year fluence projections:

- The Original Licensed Thermal Power (OLTP) level for BFN Units 1, 2 and 3 was 3293 MWt.
- By Amendment Nos. 254 and 214 (Units 2 and 3 respectively) dated September 8, 1998, the NRC approved an approximate 5 percent stretch power uprate to 3458 MWt for BFN Units 2 and 3. By Amendment No. 269 (Unit 1) dated March 6, 2007, the NRC approved an approximate 5 percent stretch power uprate to 3458 MWt for BFN Unit 1.
- By Amendment Nos. 299, 323 and 283 (Units 1, 2 and 3, respectively) dated August 14, 2017, the NRC approved an approximate 15 percent EPU (Extended Power Uprate) that authorized an increase in the maximum thermal power level from 3458 MWt to the current licensed thermal power (CLTP) level of 3952 MWt for BFN Units 1, 2, and 3. The EPU power level of 3952 MWt represents an increase of approximately 20 percent above the OLTP level of 3293 MWt.
- By Amendment Nos. 310, 333 and 293 (Units 1, 2 and 3, respectively), dated December 26, 2019, the NRC approved a Maximum Extended Load Line Limit Analysis Plus (MELLLA+) operating strategy for BFN Units 1, 2, and 3, in accordance with NEDC-33006P-A (Reference 4.8.13).

4.2.1.1 Reactor Vessel Neutron Fluence Analyses

<u>TLAA Description:</u>

Fluence projections developed using the NRC approved GEH DORT methodology have been used as inputs in the CLB reactor vessel neutron embrittlement analyses for Units 1, 2, and Unit

3 beltline components, including analyses of USE, ART, P-T limits, axial and circumferential weld failure probability, and reactor vessel reflood thermal shock. The most recent fluence projection analyses, reported in the BFN EPU license amendment (Reference 4.8.12), were developed for 60 years and 38 EFPY for Unit 1, 48 EFPY for Unit 2, and 54 EFPY for Unit 3.

The fluence projections associated with the EPU power level of 3952 MWt were used in the current 60-year reactor vessel neutron embrittlement analyses for BFN Units 1, 2, and 3 (Reference 4.8.12). The EPU fluence projections were based on the methodology in Licensing Topical Report NEDC-32983P-A (Reference 4.8.11), which was approved by the NRC in an SE for referencing in licensing actions dated September 14, 2001 (Reference 4.8.14) and in a final SE dated November 17, 2005 (Reference 4.8.15), which removed limitations for the methodology. The GEH methodology described in the LTR adheres to the guidance in Regulatory Guide 1.190 (Reference 4.8.17) for neutron flux evaluation. These current fluence analyses have been identified as TLAAs that require evaluation for the subsequent period of extended operation.

TLAA Evaluation:

Fluence projections for 80 years have been developed to evaluate the neutron fluence dependent TLAAs associated with Reactor Vessel neutron embrittlement TLAA evaluations in Sections 4.2.2 through 4.2.7. These 80-year projections are based on the TransWare RAMA Fluence Methodology.

RAMA was developed by TransWare Enterprises and is described in BWRVIP-114-A (Reference 4.8.10). The RAMA methodology, as well as TransWare's application of the methodology, have been reviewed by the NRC and given generic approval for determining fast neutron fluence in both BWR pressure vessels (Reference 4.8.10) and PWR pressure vessels (Reference 4.8.16) with no discernible bias in the computed results.

The first step in updating fluence projections from 60 years to 80 years was to update the EFPY projections, based upon past power history records, including capacity factors and power production data. In order to determine the number of EFPY applicable for 80 years, a review of cumulative neutron exposure and EFPY through recent completed operating cycles for each unit was performed. Unit 1 accumulated 18.2 EFPY at the end of the unit's 13th operating cycle, Unit 2 accumulated 31.9 EFPY at the end of the unit's 21st operating cycle, and Unit 3 accumulated 28.7 EFPY at the end of the unit's 20th operating cycle. Therefore, Unit 1 is projected to reach 50 EFPY in 80 years, Unit 2 is projected to reach 64 EFPY in 80 years, and Unit 3 is projected to reach 62 EFPY in 80 years. Unit-specific EFPY values were used in evaluating the 80-year neutron embrittlement TLAAs in Section 4.2 of the SLRA.

In 1995, 175 metric tons of US highly enriched uranium (HEU) was declared surplus to national security needs by the federal government. The preferred disposition path for this material was to blend-down the HEU and use it as fuel in commercial reactors. However, approximately 33 tons of the HEU did not meet American Society of Testing and Materials (ASTM) standards for Commercial Grade Uranium (CGU) due to higher U-232, U-234, and U-236 concentrations. The TVA and the Department of Energy (DOE) entered into a program to utilize the blended low enriched uranium (referred to as BLEU fuel) that did not meet ASTM standards. From the Spring of 2005 through the Fall of 2018, TVA loaded fuel bundles containing BLEU fuel into the BFN reactors.

The NRC Approved Electric Power Research Institute (EPRI) RAMA Neutron Fluence Methodology, which was used to construct the detailed reactor fluence models of each of the three BFN units and to perform the neutron transport and fluence calculations for the subsequent period of extended operation cannot explicitly represent the BLEU fuel in its fluence analysis calculations because it's nuclear data file does not contain the required data for the U-232, U-234, and U-236 isotopes.

Consequently, the BLEU fuel is represented as conventional CGU in the neutron fluence analysis. This has been determined to be acceptable based on the following:

- Framatome (AREVA) has determined that the void and power distributions and the fission spectra for ATRIUM-10 fuel and ATRIUM-10XM fuel were not significantly impacted by BLEU fuel. As a result, the magnitude of the fluence is almost entirely a function of the power level of the peripheral assemblies, and the presence of BLEU fuel in the peripheral fuel assemblies versus CGU fuel has an insignificant effect on the fluence (E > 1.0 MeV) at the reactor vessel wall and internals.
- The impact of BLEU fuel on the fast flux and fluence for fuel assembly components was shown by Framatome (AREVA) to be insignificant.
- BLEU fuel has been shown to have an insignificant impact on the fuel pellet radial power profile, therefore there is no significant error in the fuel assembly pin to pin power distribution introduced by modeling the BLEU fuel as CGU fuel in the neutron fluence analyses.
- The EPRI RAMA Fluence Methodology assumes that variations in fuel compositions are accounted for in the lattice physics and core simulator codes that generate the power history for fluence calculations. The lattice physics code CASMO-4 depends on a proper accounting of all fuel actinide, burnable absorber, and fission product nuclides in a fuel depletion chain. Therefore, the U-232, U-234, and U-236 isotopes in the BLEU fuel are accounted for in the CASMO-4 modeling process. The core simulator code MICROBURN-B2 uses the CASMO-4 results to perform 3D power and exposure simulations of a reactor's operating history. Therefore, the presence of the special BLEU U-232, U-234, and U-236 isotopes are implicitly accounted for in the core power/exposure calculations. The RAMA Neutron Fluence Methodology, performs fixed-source calculations, derived from the MICROBURN-B2 3D power distributions. Therefore, the neutron source for fluence calculations implicitly accounts for all fuel actinide, absorber, and fission produce nuclides.
- Relative to the extended operating license proposed for the BFN reactors, BLEU fuel has a limited operating history on the periphery of each of the BFN reactor cores. Therefore, any approximation introduced in the RAMA SLRA fluence analyses due to modeling the BLEU fuel as CGU fuel will have a limited impact on the overall analysis results when considering the full 80-year plant lifetime.
- BFN is currently in the process of phasing BLEU fuel out of the cores of all three units. The remaining inventory of BLEU fuel was used for the production of the Unit 1 Cycle 13 reload batch, which was loaded in Unit 1 in the fall of 2018 (outage U1R12). Reloads of ATRIUM-10XM fuel since that time have utilized commercial grade uranium. TVA has no plans to utilize BLEU fuel in future reloads, including ATRIUM 11 fuel.

The 80-year fluence projections have been developed by first compiling cumulative fluence resulting from each historical past operating cycle and then adding the projected fluence for future operating cycles through the subsequent period of extended operation. The 80-year fluence projections will be validated by the BFN Neutron Fluence Monitoring program (B.3.1.2).

Figure 4.2.1-1 shows the calculated reactor vessel/reactor pressure vessel (RPV) beltline for Unit 1, Figure 4.2.1-2 shows the calculated RPV beltline for Unit 2, and Figure 4.2.1-3 shows the calculated RPV beltline for Unit 3. Each beltline figure identifies RPV plates, welds, and nozzles that are within the beltline region for each unit.

For Unit 1, the upper edge of the beltline at 50 EFPY will extend to an elevation 378.5 inches above Vessel “0 inches.” The lower edge of the beltline at 50 EFPY will extend down to 206.3 inches above Vessel “0 inches. This amounts to an 80-year extended beltline total height of 172.2 inches at 50 EFPY. The 60-year beltline extended from axial elevation 206.4 inches to 378.3 inches at 38 EFPY, for a total extended beltline height of 171.9 inches.

For Unit 2, the upper edge of the beltline at 64 EFPY will extend to an elevation 380.6 inches above Vessel “0 inches.” The lower edge of the beltline at 64 EFPY will extend down to 204.8 inches above Vessel “0 inches.” This amounts to an 80-year extended beltline total height of 175.9 inches at 64 EFPY. The 60-year beltline extended from axial elevation 205 inches to 381.4 inches at 48 EFPY, for a total extended beltline height of 176.4 inches.

For Unit 3, the upper edge of the beltline at 62 EFPY will extend to an elevation 380.8 inches above Vessel “0 inches.” The lower edge of the beltline at 62 EFPY will extend down to 205.0 inches above Vessel “0 inches.” This amounts to an 80-year extended beltline total height of 175.9 inches at 62 EFPY. The 60-year beltline extended from axial elevation 204 inches to 382.7 inches at 54 EFPY, for a total extended beltline height of 178.7 inches.

For BFN Unit 1, the extended beltline grew when computed for 80 years and compared to 60 years by 0.3 inches. For BFN Unit 2, the extended beltline shrunk when computed for 80 years and compared to 60 years by 0.5 inches. For BFN Unit 3, the extended beltline shrunk when computed for 80 years and compared to 60 years by 2.8 inches. The 80-year fluence values were computed using the RAMA Fluence Methodology which is considered “best estimate.” Using this methodology, the peak fast neutron fluence values (maximum value for Shell Course 2) for 80-years are bounded by the 60-year values. The 80-year fluence projections are provided in the following tables:

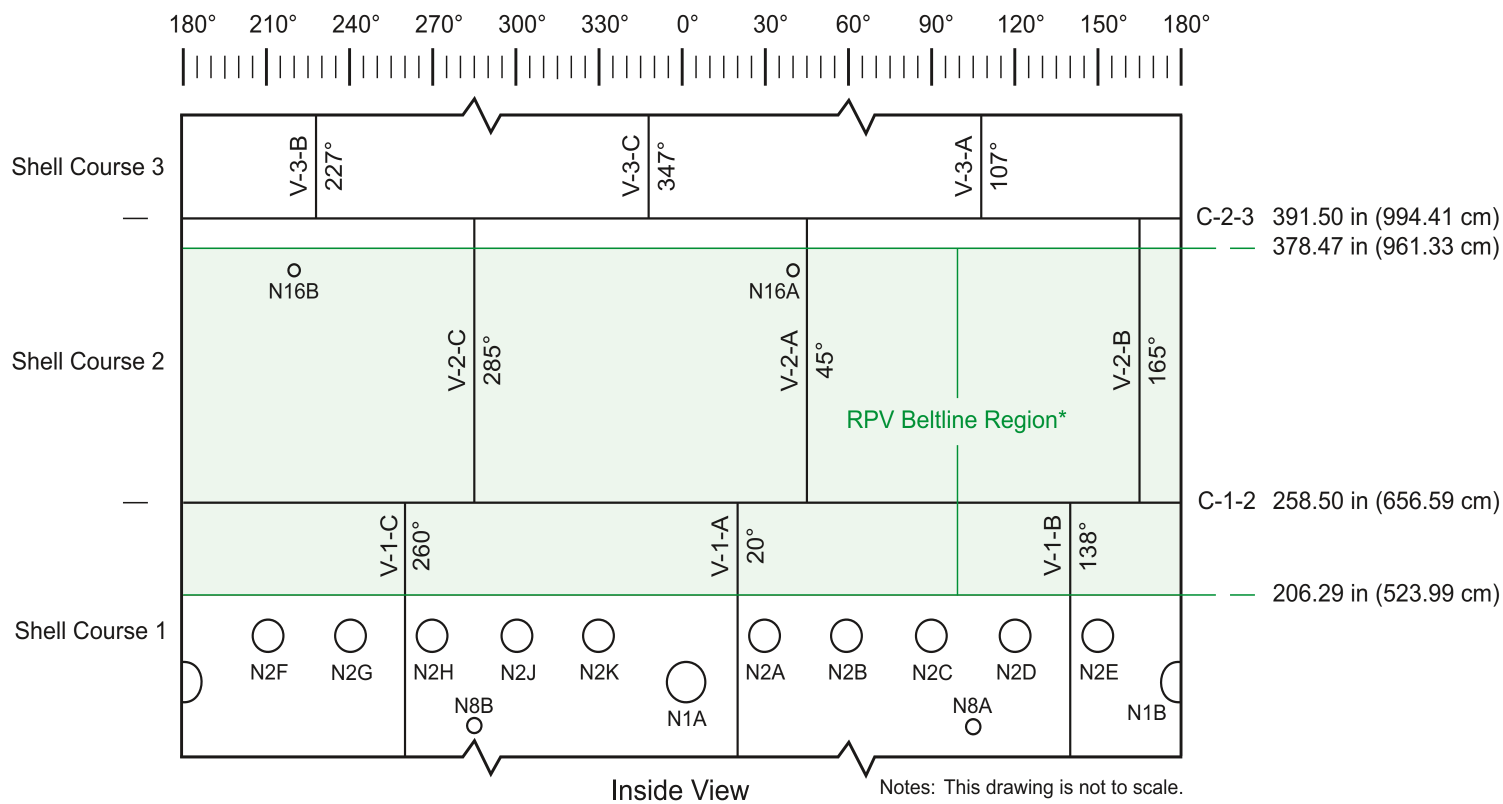
1. SLRA Table 4.2.1.1-1, BFN Unit 1 Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Shell Plates at 50 EFPY (n/cm^2)
2. SLRA Table 4.2.1.1-2, BFN Unit 1 Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Welds at 50 EFPY (n/cm^2)
3. SLRA Table 4.2.1.1-3, BFN Unit 1 Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Nozzles and Welds at 50 EFPY (n/cm^2)
4. SLRA Table 4.2.1.1-4, BFN Unit 2 Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Shell Plates at 64 EFPY (n/cm^2)
5. SLRA Table 4.2.1.1-5, BFN Unit 2 Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Welds at 64 EFPY (n/cm^2)
6. SLRA Table 4.2.1.1-6, BFN Unit 2 Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Nozzles and Welds at 64 EFPY (n/cm^2)
7. SLRA Table 4.2.1.1-7, BFN Unit 3 Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Shell Plates at 62 EFPY (n/cm^2)

8. SLRA Table 4.2.1.1-8, BFN Unit 3 Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Welds at 62 EFPY (n/cm^2)
9. SLRA Table 4.2.1.1-9, BFN Unit 3 Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Nozzles and Welds at 62 EFPY (n/cm^2)

<u>TLAA Disposition:</u>

10 CFR 54.21(c)(1)(ii) - The Unit 1, Unit 2, and Unit 3 reactor vessel beltline component fluence analyses have been satisfactorily projected through the subsequent period of extended operation. They are to be used as inputs in the Reactor Vessel neutron embrittlement TLAA evaluations in Sections 4.2.2 through 4.2.7.

Figure 4.2.1-1, BFN Unit 1 - Reactor Vessel - Beltline Components



Notes: This drawing is not to scale.
Dimensions are given in inches (centimeters).
* RPV beltline region is shown for 50 EFPY.

Table 4.2.1.1-1, BFN Unit 1 Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Shell Plates at 50 EFPY (n/cm^2)

Plate	Heat Number	0T	1/4T	3/4T
Unit 1 Shell Course 1 Plates:				
6-127-1	A0999-1	1.09E+18	7.69E+17	3.31E+17
6-127-2	B5864-1	1.09E+18	7.69E+17	3.31E+17
6-127-4	A1009-1	1.09E+18	7.69E+17	3.31E+17
Unit 1 Shell Course 2 Plates:				
6-139-19	C2884-2	1.34E+18	9.45E+17	4.02E+17
6-139-20	C2368-2	1.34E+18	9.45E+17	4.02E+17
6-139-21	C2753-1	1.34E+18	9.45E+17	4.02E+17

Table 4.2.1.1-2, BFN Unit 1 Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Welds at 50 EFPY (n/cm^2)

Weld No.	Heat Number	0T	1/4T	3/4T
Unit 1 Shell Course 1 Axial Welds:				
V-1-A	-	1.02E+18	7.26E+17	3.16E+17
V-1-B	-	7.65E+17	5.45E+17	2.42E+17
V-1-C	-	6.29E+17	4.49E+17	2.01E+17
Unit 1 Shell Course 2 Axial Welds:				
V-2-A	-	9.37E+17	6.70E+17	2.97E+17
V-2-B	-	1.11E+18	7.87E+17	3.43E+17
V-2-C	-	1.08E+18	7.68E+17	3.33E+17
Unit 1 Shell Course 1-to-2 Circumferential Weld:				
C-1-2	406L44	1.09E+18	7.69E+17	3.31E+17

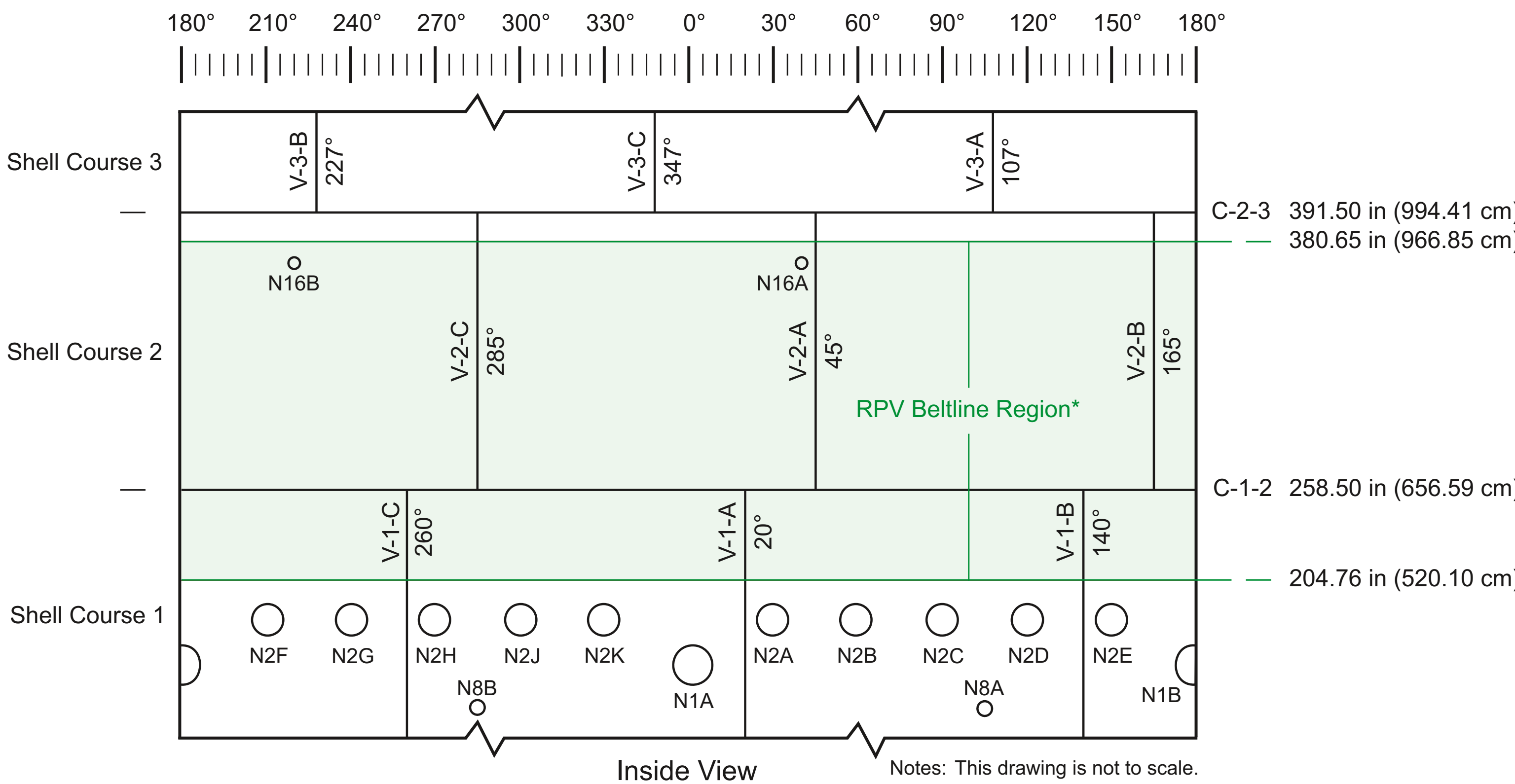
Table 4.2.1.1-3, BFN Unit 1 Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Nozzles and Welds at 50 EFPY (n/cm^2)

Nozzle No. / Location	Heat Number	0T	1/4T	3/4T
Unit 1 N16 Water Level Instrumentation (WLI) Nozzles and Welds:				
N16 Nozzle Weld	8564	2.65E+17	1.82E+17	8.25E+16

Notes:

1. The N16 WLI nozzle forging and weld are fabricated from a non-ferritic alloy which does not require evaluation of loss of fracture toughness. A loss of fracture toughness evaluation on the surrounding ferritic shell material is provided in Section 4.2.2.

Figure 4.2.1-2, BFN Unit 2 - Reactor Vessel - Beltline Components



Notes: This drawing is not to scale.
Dimensions are given in inches (centimeters).
* RPV beltline region is shown for 64 EFPY.

Table 4.2.1.1-4, BFN Unit 2 Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Shell Plates at 64 EFPY (n/cm^2)

Plate	Heat Number	0T	1/4T	3/4T
Unit 2 Shell Course 1 Plates:				
6-127-14	C2467-2	1.34E+18	9.48E+17	4.10E+17
6-127-15	C2463-1	1.34E+18	9.48E+17	4.10E+17
6-127-17	C2460-2	1.34E+18	9.48E+17	4.10E+17
Unit 2 Shell Course 2 Plates:				
6-127-6	A0981-1	1.69E+18	1.19E+18	5.06E+17
6-127-16	C2467-1	1.69E+18	1.19E+18	5.06E+17
6-127-20	C2849-1	1.69E+18	1.19E+18	5.06E+17

Table 4.2.1.1-5, BFN Unit 2 Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Welds at 64 EFPY (n/cm^2)

Weld No.	Heat Number	0T	1/4T	3/4T
Unit 2 Shell Course 1 Axial Welds:				
V-1-A	-	1.26E+18	8.93E+17	3.89E+17
V-1-B	-	9.60E+17	6.86E+17	3.06E+17
V-1-C	-	7.65E+17	5.48E+17	2.46E+17
Unit 2 Shell Course 2 Axial Welds:				
V-2-A	-	1.21E+18	8.61E+17	3.81E+17
V-2-B	-	1.39E+18	9.84E+17	4.28E+17
V-2-C	-	1.36E+18	9.67E+17	4.19E+17
Unit 2 Shell Course 1-to-2 Circumferential Weld:				
C-1-2	D55733	1.34E+18	9.48E+17	4.10E+17

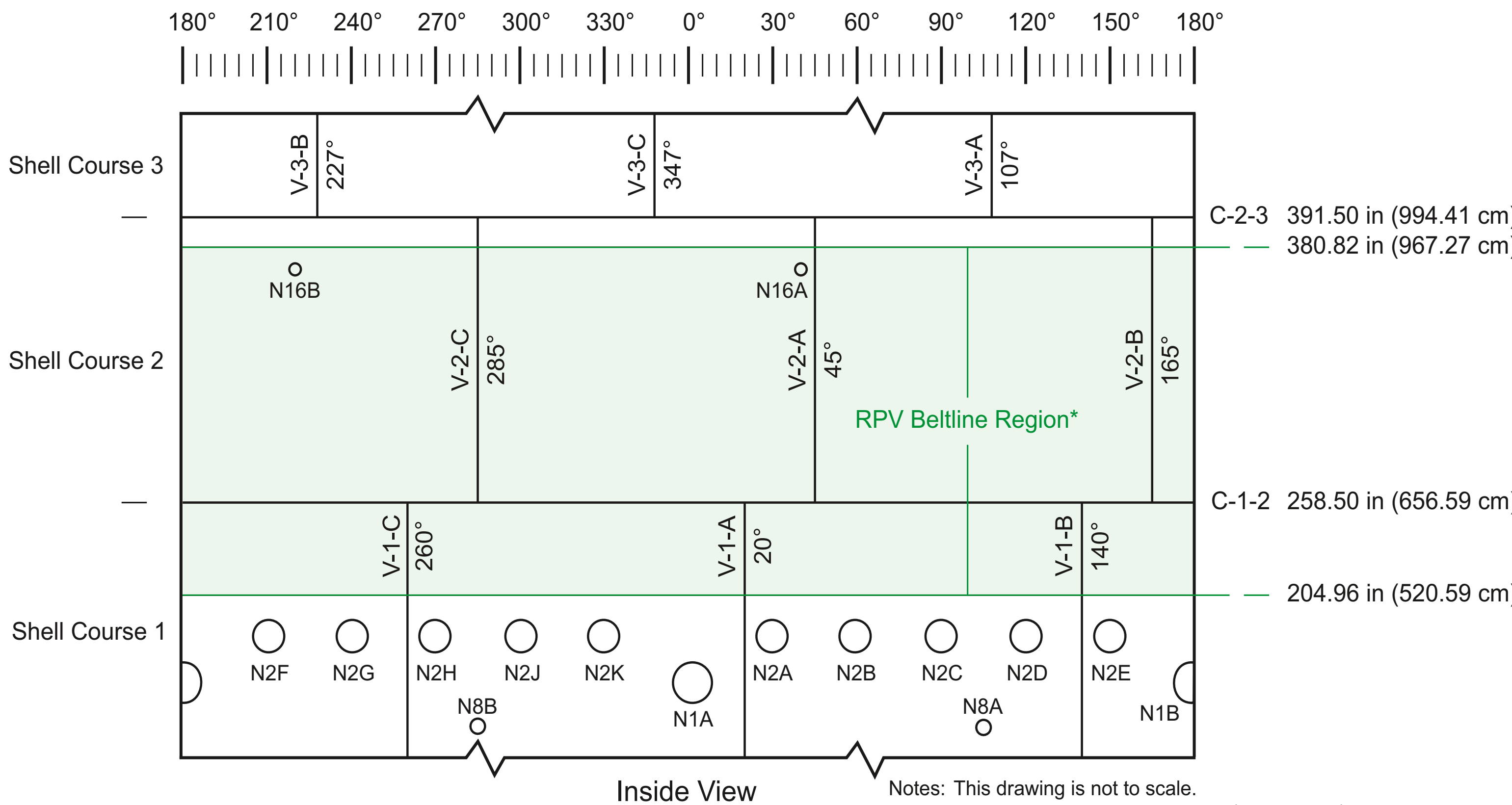
Table 4.2.1.1-6, BFN Unit 2 Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Nozzles and Welds at 64 EFPY (n/cm^2)

Nozzle No. / Location	Heat Number	0T	1/4T	3/4T
Unit 2 N16 Water Level Instrumentation (WLI) Nozzles and Welds:				
N16 Nozzle Weld	8601	3.47E+17	2.42E+17	1.15E+17

Notes:

1. The N16 WLI nozzle forging and weld are fabricated from a non-ferritic alloy which does not require evaluation of loss of fracture toughness. A loss of fracture toughness evaluation on the surrounding ferritic shell material is presented in Section 4.2.2.

Figure 4.2.1-3, BFN Unit 3 - Reactor Vessel - Beltline Components



Notes: This drawing is not to scale.
Dimensions are given in inches (centimeters).
* RPV beltline region is shown for 62 EFPY.

Table 4.2.1.1-7, BFN Unit 3 Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Shell Plates at 62 EFPY (n/cm^2)

Plate	Heat Number	0T	1/4T	3/4T
Unit 3 Shell Course 1 Plates:				
6-145-4	C3222-2	1.29E+18	9.16E+17	3.96E+17
6-145-7	C3213-1	1.29E+18	9.16E+17	3.96E+17
6-145-12	C3217-2	1.29E+18	9.16E+17	3.96E+17
Unit 3 Shell Course 2 Plates:				
6-145-1	C3201-2	1.63E+18	1.14E+18	4.88E+17
6-145-2	C3188-2	1.63E+18	1.14E+18	4.88E+17
6-145-6	B7267-1	1.63E+18	1.14E+18	4.88E+17

Table 4.2.1.1-8, BFN Unit 3 Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Welds at 62 EFPY (n/cm^2)

Weld No.	Heat Number	0T	1/4T	3/4T
Unit 3 Shell Course 1 Axial Welds:				
V-1-A	-	1.22E+18	8.65E+17	3.76E+17
V-1-B	-	9.28E+17	6.63E+17	2.96E+17
V-1-C	-	7.41E+17	5.31E+17	2.38E+17
Unit 3 Shell Course 2 Axial Welds:				
V-2-A	-	1.16E+18	8.27E+17	3.66E+17
V-2-B	-	1.34E+18	9.49E+17	4.13E+17
V-2-C	-	1.31E+18	9.31E+17	4.03E+17
Unit 3 Shell Course 1-to-2 Circumferential Weld:				
C-1-2	D55733	1.29E+18	9.16E+17	3.96E+17

Table 4.2.1.1-9, BFN Unit 3 Maximum Neutron Fluence (>1.0 MeV) in RPV Beltline Nozzles and Welds at 62 EFPY (n/cm^2)

Nozzle No. / Location	Heat Number	0T	1/4T	3/4T
Unit 3 N16 Water Level Instrumentation (WLI) Nozzles and Welds:				
N16 Nozzle Weld	8601	3.44E+17	2.40E+17	1.13E+17

Notes:

1. The N16 WLI nozzle forging and weld are fabricated from a non-ferritic alloy which does not require evaluation of loss of fracture toughness. A loss of fracture toughness evaluation on the surrounding ferritic shell material is provided in Section 4.2.2.

4.2.1.2 Reactor Vessel Internals Neutron Fluence Analyses

<u>TLAA Description:</u>

Neutron fluence exposure has been used as input in analyses of BFN Units 1, 2, and 3 reactor vessel internals components, including the core shroud, top guide, core plate and core plate bolts, and jet pumps (and jet pump repair hardware). In addition, fluence projections are used to determine when specified fluence threshold values may be exceeded to invoke specific aging management requirements, such as inspections. Since the neutron fluence exposure is time dependent, these analyses have been identified as TLAAs that require evaluation for the subsequent period of extended operation.

<u>TLAA Evaluation:</u>

Fluence projections for 80 years have been developed to evaluate the neutron fluence dependent TLAAs associated with components in SLRA Sections 4.2.8 through 4.2.19. These 80-year projections are based on the TransWare RAMA Fluence Methodology.

The RAMA methodology has received conditional approval for determining fast neutron fluence of reactor vessel internals in light water reactors. The NRC SE for EPRI report BWRVIP-145 (Reference 4.8.37) concludes that “for applications such as IASCC, crack propagation rates and weldability determinations, the RAMA methodology can be used in determining fast neutron fluence values in the core shroud and top guide … for licensing actions provided that the calculational results are supported by sufficient justification that the proposed values are conservative for the intended application.”

The fast neutron fluence methods discussed in the BFN Fluence Methodology Report meet the requirements of 10 CFR 50 Appendices G and H and Regulatory Guides 1.190 and 1.99 Revision 2. The NRC has not issued a regulatory guide of similar scope to Regulatory Guide 1.190 for determining fluence in reactor vessel internal components. In the absence of detailed regulatory guidance, the intent of Regulatory Guide 1.190, particularly with regards to conservatism in constructing and evaluating reactor components, is used by TransWare in the determination of fast neutron fluence throughout a reactor vessel.

In February 2008, the NRC reviewed BWRVIP-145-A which documented the use of RAMA methodology to calculate fluence values for the core shroud and top guide samples removed from Susquehanna Unit 2 after 11 cycles of irradiation. The report compares the measured fluence results from the Susquehanna samples with the corresponding RAMA calculated fluence values. The NRC concluded there was reasonable agreement between the calculated fluence values and measured fluence values. The NRC found that for applications related to IASCC, crack propagation rates, and weldability determinations, the RAMA methodology can be used to determine the fast neutron fluence values in the core shroud and top guide (References 4.8.37, 4.8.38, 4.8.39).

BWRVIP-145-A and the associated NRC SE (Reference 4.8.37) are referenced here for satisfying the location, geometry, and accuracy requirements specified in the SER for BWRVIP-114-A (Reference 4.8.40). The BFN reactors are of the same BWR/4 design as Susquehanna Unit 2, with 251-3/8 inch inside diameter reactors vessels (Reference 4.8.41, 4.8.44), 764 fuel bundles (Reference 4.8.42), and core shrouds with a 207-1/8 inch outside diameter (Reference 4.8.43, 4.8.44). Since there are similarities in vessel and internals dimensions, and the same RAMA methodology is used, the resulting fluence calculation accuracies for BFN internals are comparable to those presented in BWRVIP-145-A. Therefore, use of RAMA methodology to calculate projected fluence values for the BFN reactor vessel internal components, such as the core shroud, top guide, core plate and core plate bolts, and jet pumps (and jet pump repair hardware) is acceptable.

The 80-year RAMA fluence projections for some Unit 1, Unit 2, and Unit 3 Reactor Vessel internal components are provided in the following tables.

- SLRA Table 4.2.1.2-1, Unit 1 Reactor Vessel Internal Component Fluence Projections
- SLRA Table 4.2.1.2-2, Unit 2 Reactor Vessel Internal Component Fluence Projections
- SLRA Table 4.2.1.2-3, Unit 3 Reactor Vessel Internal Component Fluence Projections

The 80-year fluence projections will be validated by the BFN Neutron Fluence Monitoring program (B.3.1.2).

<u>TLAA Disposition:</u>

10 CFR 54.21(c)(1)(ii) - The Unit 1, Unit 2, and Unit 3 reactor vessel internal component fluence analyses have been satisfactorily projected through the subsequent period of extended operation. They are to be used as inputs in the reactor vessel internal components fluence-related TLAA evaluations in Sections 4.2.8 through 4.2.19.

Table 4.2.1.2-1, Unit 1 Reactor Vessel Internal Component Fluence Projections

Component	50 EFPY Fluence (n/cm^2)
Core Shroud Vertical Welds	2.43E+21
Core Shroud Horizontal Welds	2.13E+21
Core Plate Rim Hold-Down Bolt	1.16E+20
Jet Pump Slip Joint Clamp	4.98E+18
Jet Pump Auxiliary Spring Wedge Assembly	1.52E+20
Jet Pump Riser Weld RS-1	4.77E+15

Table 4.2.1.2-2, Unit 2 Reactor Vessel Internal Component Fluence Projections

Component	64 EFPY Fluence (n/cm^2)
Core Shroud Vertical Welds	1.01E+21
Core Shroud Horizontal Welds	2.61E+21
Core Plate Rim Hold-Down Bolt	1.41E+20
Jet Pump Slip Joint Clamp	6.83E+18
Jet Pump Auxiliary Spring Wedge Assembly	1.55E+20
Jet Pump Riser Weld RS-1	5.86E+15

Table 4.2.1.2-3, Unit 3 Reactor Vessel Internal Component Fluence Projections

Component	62 EFPY Fluence (n/cm^2)
Core Shroud Vertical Welds	1.52E+21
Core Shroud Horizontal Welds	2.56E+21
Core Plate Rim Hold-Down Bolt	1.39E+20
Jet Pump Auxiliary Spring Wedge Assembly	1.55E+20
Jet Pump Riser Weld RS-1	5.69E+15

4.2.2 Reactor Vessel Upper-Shelf Energy (USE) Analyses

TLAA Description:

Appendix G of 10 CFR 50, (Reference 4.8.8, Paragraph IV.A.1.a), states that reactor vessel beltline materials must have Charpy USE of no less than 75 ft-lb initially and must maintain Charpy USE throughout the life of the vessel of no less than 50 ft lb, unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy USE will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code.

The BFN Units 1, 2, and 3 reactor vessels were designed and fabricated prior to the current requirements going into effect, and as a result, there is insufficient data available to establish the unirradiated USE value for all beltline materials for these reactors. Therefore, the current licensing basis Charpy USE evaluations are based upon Equivalent Margin Analysis (EMA) as specified in BWRVIP-74-A (Reference 4.8.26), which meet the alternative requirements specified above. The end-of-life USE calculations satisfy the criteria of 10 CFR 54.3(a). As such, these analyses have been identified as TLAAs requiring evaluation for the subsequent period of extended operation.

TLAA Evaluation:

The 80-year fluence values described in Section 4.2.1 were used to develop revised EMA values that have been compared to the applicable design limits from BWRVIP-74-A. The 1/4T fluence values for each location were derived from the plant-specific displacement per atom (dpa) attenuation method described in Regulatory Guide 1.99, Revision 2 (Reference 4.8.27). The EMA was performed for the limiting beltline plate, nozzle, and weld materials for 80 years of operation and compared against the 54 EFPY limits defined in Appendix B of BWRVIP-74-A. The USE for the Water Level Instrument (WLI) nozzle is based upon adjacent reactor vessel shell material because the forging is fabricated from Inconel materials.

- SLRA Table 4.2.2-1 summarizes the 60-year EMA values, the 80-year EMA values, and the design limits for the limiting Unit 1 reactor vessel materials. All materials are shown to be acceptable with respect to the design limits.
- SLRA Table 4.2.2-2 summarizes the 60-year EMA values, the 80-year EMA values, and the design limits for the limiting Unit 2 reactor vessel materials. All materials are shown to be acceptable with respect to the design limits.
- SLRA Table 4.2.2-3 summarizes the 60-year EMA values, the 80-year EMA values, and the design limits for the limiting Unit 3 reactor vessel materials. All materials are shown to be acceptable with respect to the design limits.
- SLRA Table 4.2.2-4 provides the EMA for the limiting Unit 1 plate materials.
- SLRA Table 4.2.2-5 provides the EMA for the limiting Unit 1 nozzle materials.
- SLRA Table 4.2.2-6 provides the EMA for the limiting Unit 1 weld materials.
- SLRA Table 4.2.2-7 provides the EMA for the limiting Unit 2 plate materials.
- SLRA Table 4.2.2-8 provides the EMA for the limiting Unit 2 nozzle materials.
- SLRA Table 4.2.2-9 provides the EMA for the limiting Unit 2 weld materials.
- SLRA Table 4.2.2-10 provides the EMA for the limiting Unit 3 plate materials.
- SLRA Table 4.2.2-11 provides the EMA for the limiting Unit 3 nozzle materials.
- SLRA Table 4.2.2-12 provides the EMA for the limiting Unit 3 weld materials.

TLAA Disposition:

10 CFR 54.21(c)(1)(ii) - The reactor vessel USE analyses have been projected through the subsequent period of extended operation.

Table 4.2.2-1, Comparison of Unit 1 60-Year USE to 80-Year for Limiting Beltline Materials

Item	Analysis	Limiting Beltline Material	60-Year % Decrease in USE	80-Year % Decrease in USE	Allowable % Decrease in Design Limit from BWRVIP-74-A	80-Year to 60-Year Comparison
1	Unit 1 USE/ EMA	Plate Heat B5864-1	15.5	13.1	**{{ }}**	The 80-year % decrease is lower, and the USE/EMA remains below the 54 EFPY limits.
2	Unit 1 USE/ EMA	Nozzle Forging Material [3]	N/A [4]	8.1	**{{ }}**	The 80-year % USE/EMA is determined to be below the 54 EFPY limits.
3	Unit 1 USE/ EMA	Weld Heat 406L44	26.5	29.5	**{{ }}**	The 80-year % decrease is higher, and the USE/EMA remains below the 54 EFPY limits.

Notes:

1. BFN Unit 1 requires a USE evaluation in accordance with EMA because there is insufficient data available to establish an unirradiated USE value for all beltline materials.
2. The design limit for USE is 50 ft lbs at the end of license. The EMA method described in BWRVIP-74-A provides the design limits based upon percent decrease in USE that equates to the 50 ft-lbs requirement. For 60 years of operation, the plate limit is **{{ }}** and the weld limit is **{{ }}**. The 80-year values for percent decrease in USE have been demonstrated to remain below the 60-year (54 EFPY) limits.
3. The N16 WLI nozzle forging, and weld are fabricated from non-ferritic materials which do not require fracture toughness evaluation. USE for the WLI nozzle is based upon adjacent reactor vessel shell materials because the forging is fabricated from Inconel materials.
4. 60-year USE for the N16 nozzle was not previously calculated.

Table 4.2.2-2, Comparison of Unit 2 60-Year USE to 80-Year for Limiting Beltline Materials

Item	Analysis	Limiting Beltline Material	60-Year % Decrease in USE	80-Year % Decrease in USE	Allowable % Decrease in Design Limit from BWRVIP-74-A	80-Year to 60-Year Comparison
1	Unit 2 USE/EMA	Plate Heat C2467-1	17	15.1	**{{ }}**	The 80-year % decrease is lower, and the USE/EMA remains below the 52 EFPY limits.
2	Unit 2 USE/EMA	Nozzle Forging Material [3]	N/A [4]	10.4	**{{ }}**	The 80-year % USE/EMA is determined to be below the 52 EFPY limits.
3	Unit 2 USE/EMA	ESW	25.5	21.9	**{{ }}**	The 80-year % decrease is lower, and the USE/EMA remains below the 52 EFPY limits.

Notes:

1. BFN Unit 2 requires a USE evaluation in accordance with EMA because there is insufficient data available to establish an unirradiated USE value for all beltline materials.
2. The design limit for USE is 50 ft lbs at the end of license. The EMA method described in BWRVIP-74-A provides the design limits based upon percent decrease in USE that equates to the 50 ft-lbs requirement. For 60 years of operation, the plate limit is **{{ }}** and the weld limit is **{{ }}**. The 80-year values for percent decrease in USE have been demonstrated to remain below the 60-year (52 EFPY) limits.
3. The N16 WLI nozzle forging, and weld are fabricated from non-ferritic materials which do not require fracture toughness evaluation. USE for the WLI nozzle is based upon adjacent reactor vessel shell materials because the forging is fabricated from Inconel materials.
4. 60-year USE for the N16 nozzle was not previously calculated.

Table 4.2.2-3, Comparison of Unit 3 60-Year USE to 80-Year for Limiting Beltline Materials

Item	Analysis	Limiting Beltline Material	60-Year % Decrease in USE	80-Year % Decrease in USE	Allowable % Decrease in Design Limit from BWRVIP-74-A	80-Year to 60-Year Comparison
1	Unit 3 USE/ EMA	Plate Heat A0981-1	16	13.6	**{{ }}**	The 80-year % decrease is lower, and the USE/EMA remains below the 52 EFPY limits.
2	Unit 3 USE/ EMA	Nozzle Forging Material [3]	N/A [4]	9.1	**{{ }}**	The 80-year % USE/EMA is determined to be below the 52 EFPY limits.
3	Unit 3 USE/ EMA	Weld Heat C3222-2	25.5	21.8	**{{ }}**	The 80-year % decrease is lower, and the USE/EMA remains below the 52 EFPY limits.

Notes:

1. BFN Unit 3 requires a USE evaluation in accordance with EMA because there is insufficient data available to establish an unirradiated USE value for all beltline materials.
2. The design limit for USE is 50 ft lbs at the end of license. The EMA method described in BWRVIP-74-A provides the design limits based upon percent decrease in USE that equates to the 50 ft-lbs requirement. For 60 years of operation, the plate limit is **{{ }}** and the weld limit is **{{ }}**. The 80-year values for percent decrease in USE have been demonstrated to remain below the 60-year (52 EFPY) limits.
3. The N16 WLI nozzle forging, and weld are fabricated from non-ferritic materials which do not require fracture toughness evaluation. USE for the WLI nozzle is based upon adjacent reactor vessel shell materials because the forging is fabricated from Inconel materials.
4. 60-year USE for the N16 nozzle was not previously calculated.

Table 4.2.2-4, Unit 1 Equivalent Margin Analysis for 50 EFPY BWR/3-6 Plate

Integrated Surveillance Program Plate USE (Heat A0981-1):		
%Cu	=	0.14
1st Capsule Fluence	=	2.40E+17 n/cm^2
2nd Capsule Fluence	=	6.44E+17 n/cm^2
1st Capsule Measured % Decrease	=	6.0 (Charpy Curves)
1st Capsule Regulatory Guide (RG) 1.99 Predicted % Decrease	=	9.5 (RG 1.99, Rev. 2, Figure 2)
2nd Capsule Measured % Decrease	=	-3.6 (Charpy Curves)
2nd Capsule RG 1.99 Predicted % Decrease	=	12.0 (RG 1.99, Rev. 2, Figure 2)
Limiting Beltline Plate USE (Heat B5864-1, Lower Shell #2):		
%Cu	=	0.15
50 EFPY Peak ID Fluence	=	1.09E+18 n/cm^2
50 EFPY 1/4T Fluence	=	7.69E+17 n/cm^2
RG 1.99 Predicted % Decrease	=	13.1 (RG 1.99, Rev. 2, Figure 2)
Adjusted % Decrease	=	N/A (RG 1.99, Rev. 2, Position 2.2)
Comparison of Limiting % Decrease Value to Limit:		
13.1%	≤	**{{ }}**
Therefore, Unit 1 vessel plates are bounded by Equivalent Margin Analysis		

Table 4.2.2-5, Unit 1 Equivalent Margin Analysis for 50 EFPY Nozzle Using BWR/3-6 Plate

Integrated Surveillance Program Plate USE (Heat A0981-1):		
%Cu	=	0.14
1st Capsule Fluence	=	2.40E+17 n/cm^2
2nd Capsule Fluence	=	6.44E+17 n/cm^2
1st Capsule Measured % Decrease	=	6.0 (Charpy Curves)
1st Capsule RG 1.99 Predicted % Decrease	=	9.5 (RG 1.99, Rev. 2, Figure 2)
2nd Capsule Measured % Decrease	=	-3.6 (Charpy Curves)
2nd Capsule RG 1.99 Predicted % Decrease	=	12.0 (RG 1.99, Rev. 2, Figure 2)
Limiting Beltline Plate USE (Heat C2884-2, Lower-Intermediate Shell #11):		
%Cu	=	0.12
50 EFPY Peak ID Fluence	=	2.65E+17 n/cm^2
50 EFPY 1/4T Fluence	=	1.82E+17 n/cm^2
RG 1.99 Predicted % Decrease	=	8.1 (RG 1.99, Rev. 2, Figure 2)
Adjusted % Decrease	=	N/A (RG 1.99, Rev. 2, Position 2.2)
Comparison of Limiting % Decrease Value to Limit:		
8.1%	≤	**{{ }}**
Therefore, Unit 1 vessel nozzles are bounded by Equivalent Margin Analysis		

Notes:

1. N16 WLI nozzle is non-ferritic material, therefore %Cu for adjacent shell plate is used, with nozzle fluence.

Table 4.2.2-6, Unit 1 Equivalent Margin Analysis For 50 EFPY BWR/2-6 Weld

Integrated Surveillance Program Plate USE (Heat SSP 406L44):		
%Cu	=	0.29
1st Capsule Fluence	=	1.00E+18 n/cm^2
2nd Capsule Fluence	=	1.83E+18 n/cm^2
3rd Capsule Fluence	=	1.77E+18 n/cm^2
4th Capsule Fluence	=	2.89E+18 n/cm^2
5th Capsule Fluence	=	3.97E+17 n/cm^2
6th Capsule Fluence	=	4.93E+17 n/cm^2
1st Capsule Measured % Decrease	=	31.5 (Charpy Curves)
1st Capsule RG 1.99 Predicted % Decrease	=	24.9 (R.G. 1.99, Figure 2)
2nd Capsule Measured % Decrease	=	32.6 (Charpy Curves)
2nd Capsule RG 1.99 Predicted % Decrease	=	28.8 (R.G. 1.99, Figure 2)
3rd Capsule Measured % Decrease	=	36.2 (Charpy Curves)
3rd Capsule RG 1.99 Predicted % Decrease	=	28.5 (R.G. 1.99, Figure 2)
4th Capsule Measured % Decrease	=	42.3 (Charpy Curves)
4th Capsule RG 1.99 Predicted % Decrease	=	32.0 (R.G. 1.99, Figure 2)
5th Capsule Measured % Decrease	=	20.5 (Charpy Curves)
5th Capsule RG 1.99 Predicted % Decrease	=	20.0 (R.G. 1.99, Figure 2)
6th Capsule Measured % Decrease	=	20.6 (Charpy Curves)
6th Capsule RG 1.99 Predicted % Decrease	=	21.1 (R.G. 1.99, Figure 2)
Limiting Beltline Plate USE (Heat 406L44):		
%Cu	=	0.27
50 EFPY Peak ID Fluence	=	1.09E+18 n/cm^2
50 EFPY 1/4T Fluence	=	7.69E+17 n/cm^2
RG 1.99 Predicted % Decrease	=	22.3 (RG 1.99, Rev. 2, Figure 2)
Adjusted % Decrease	=	29.5 (RG 1.99, Rev. 2, Position 2.2)
Comparison of Limiting % Decrease Value to Limit:		
29.5%	≤	**{{ }}**
Therefore, Unit 1 vessel welds are bounded by Equivalent Margin Analysis		

Table 4.2.2-7, Unit 2 Equivalent Margin Analysis for 64 EFPY BWR/3-6 Plate

Integrated Surveillance Program Plate USE (Heat A0981-1):		
%Cu	=	0.14
1st Capsule Fluence	=	2.40E+17 n/cm^2
2nd Capsule Fluence	=	6.44E+17 n/cm^2
1st Capsule Measured % Decrease	=	6.0 (Charpy Curves)
1st Capsule RG 1.99 Predicted % Decrease	=	9.5 (RG 1.99, Rev. 2, Figure 2)
2nd Capsule Measured % Decrease	=	-3.6 (Charpy Curves)
2nd Capsule RG 1.99 Predicted % Decrease	=	12.0 (RG 1.99, Rev. 2, Figure 2)
Limiting Beltline Plate USE (Heat C2467-1, Lower Intermediate Shell #2):		
%Cu	=	0.16
64 EFPY Peak ID Fluence	=	1.69E+18 n/cm^2
64 EFPY 1/4T Fluence	=	1.19E+18 n/cm^2
RG 1.99 Predicted % Decrease	=	15.1 (RG 1.99, Rev. 2, Figure 2)
Adjusted % Decrease	=	N/A (RG 1.99, Rev. 2, Position 2.2)
Comparison of Limiting % Decrease Value to Limit:		
15.1%	≤	**{{ }}**
Therefore, Unit 2 vessel plates are bounded by Equivalent Margin Analysis		

Table 4.2.2-8, Unit 2 Equivalent Margin Analysis for 64 EFPY Nozzle Using BWR/3-6 Plate

Integrated Surveillance Program Plate USE (Heat A0981-1):		
%Cu	=	0.14
1st Capsule Fluence	=	2.40E+17 n/cm^2
2nd Capsule Fluence	=	6.44E+17 n/cm^2
1st Capsule Measured % Decrease	=	6.0 (Charpy Curves)
1st Capsule RG 1.99 Predicted % Decrease	=	9.5 (RG 1.99, Rev. 2, Figure 2)
2nd Capsule Measured % Decrease	=	-3.6 (Charpy Curves)
2nd Capsule RG 1.99 Predicted % Decrease	=	12.0 (RG 1.99, Rev. 2, Figure 2)
Limiting Beltline Plate USE (Heat C2467-1, Lower-Intermediate Shell #21):		
%Cu	=	0.16
64 EFPY Peak ID Fluence	=	3.47E+17 n/cm^2
64 EFPY 1/4T Fluence	=	2.42E+17 n/cm^2
RG 1.99 Predicted % Decrease	=	10.4 (RG 1.99, Rev. 2, Figure 2)
Adjusted % Decrease	=	N/A (RG 1.99, Rev. 2, Position 2.2)
Comparison of Limiting % Decrease Value to Limit:		
10.4%	≤	**{{ }}**
Therefore, Unit 2 vessel nozzles are bounded by Equivalent Margin Analysis		

Notes:

1. N16 WLI nozzle is non-ferritic material, therefore %Cu for adjacent shell plate is used, with nozzle fluence.

Table 4.2.2-9, Unit 2 Equivalent Margin Analysis For 64 EFPY BWR/2-6 Weld

Integrated Surveillance Program Plate USE (Heat A0981-1):		
%Cu	=	0.2
1st Capsule Fluence	=	2.40E+17 n/cm^2
2nd Capsule Fluence	=	6.44E+17 n/cm^2
1st Capsule Measured % Decrease	=	5.9 (Charpy Curves)
1st Capsule RG 1.99 Predicted % Decrease	=	14.1 (R.G. 1.99, Figure 2)
2nd Capsule Measured % Decrease	=	3.4 (Charpy Curves)
2nd Capsule RG 1.99 Predicted % Decrease	=	17.8 (R.G. 1.99, Figure 2)
Limiting Beltline Plate USE (ESW):		
%Cu	=	0.24
64 EFPY Peak ID Fluence	=	1.39E+18 n/cm^2
64 EFPY 1/4T Fluence	=	9.84E+17 n/cm^2
RG 1.99 Predicted % Decrease	=	21.9 (RG 1.99, Rev. 2, Figure 2)
Adjusted % Decrease	=	N/A (RG 1.99, Rev. 2, Position 2.2)
Comparison of Limiting % Decrease Value to Limit:		
21.9%	≤	**{{ }}**
Therefore, Unit 2 vessel welds are bounded by Equivalent Margin Analysis		

Table 4.2.2-10, Unit 3 Equivalent Margin Analysis for 62 EFPY BWR/3-6 Plate

Integrated Surveillance Program Plate USE (Heat A0981-1):		
%Cu	=	0.14
1st Capsule Fluence	=	2.40E+17 n/cm^2
2nd Capsule Fluence	=	6.44E+17 n/cm^2
1st Capsule Measured % Decrease	=	6.0 (Charpy Curves)
1st Capsule RG 1.99 Predicted % Decrease	=	9.5 (RG 1.99, Rev. 2, Figure 2)
2nd Capsule Measured % Decrease	=	-3.6 (Charpy Curves)
2nd Capsule RG 1.99 Predicted % Decrease	=	12.0 (RG 1.99, Rev. 2, Figure 2)
Limiting Beltline Plate USE (Heat C3222-2, Lower Shell #1):		
%Cu	=	0.15
62 EFPY Peak ID Fluence	=	1.29E+18 n/cm^2
62 EFPY 1/4T Fluence	=	9.16E+17 n/cm^2
RG 1.99 Predicted % Decrease	=	13.6 (RG 1.99, Rev. 2, Figure 2)
Adjusted % Decrease	=	N/A (RG 1.99, Rev. 2, Position 2.2)
Comparison of Limiting % Decrease Value to Limit:		
13.6%	≤	**{{ }}**
Therefore, Unit 3 vessel plates are bounded by Equivalent Margin Analysis		

Table 4.2.2-11, Unit 3 Equivalent Margin Analysis for 62 EFPY Nozzle Using BWR/3-6 Plate

Integrated Surveillance Program Plate USE (Heat A0981-1):		
%Cu	=	0.14
1st Capsule Fluence	=	2.40E+17 n/cm^2
2nd Capsule Fluence	=	6.44E+17 n/cm^2
1st Capsule Measured % Decrease	=	6.0 (Charpy Curves)
1st Capsule RG 1.99 Predicted % Decrease	=	9.5 (RG 1.99, Rev. 2, Figure 2)
2nd Capsule Measured % Decrease	=	-3.6 (Charpy Curves)
2nd Capsule RG 1.99 Predicted % Decrease	=	12.0 (RG 1.99, Rev. 2, Figure 2)
Limiting Beltline Plate USE (Heat C3201-2, Lower-Intermediate Shell #11):		
%Cu	=	0.13
62 EFPY Peak ID Fluence	=	3.44E+17 n/cm^2
62 EFPY 1/4T Fluence	=	2.40E+17 n/cm^2
RG 1.99 Predicted % Decrease	=	9.1 (RG 1.99, Rev. 2, Figure 2)
Adjusted % Decrease	=	N/A (RG 1.99, Rev. 2, Position 2.2)
Comparison of Limiting % Decrease Value to Limit:		
9.1%	≤	**{{ }}**
Therefore, Unit 3 vessel nozzles are bounded by Equivalent Margin Analysis		

Notes:

1. N16 WLI nozzle is non-ferritic material, therefore %Cu for adjacent shell plate is used, with nozzle fluence.

Table 4.2.2-12, Unit 3 Equivalent Margin Analysis For 62 EFPY BWR/2-6 Weld

Integrated Surveillance Program Plate USE (Heat A0981-1):		
%Cu	=	0.2
1st Capsule Fluence	=	2.40E+17 n/cm^2
2nd Capsule Fluence	=	6.44E+17 n/cm^2
1st Capsule Measured % Decrease	=	5.9 (Charpy Curves)
1st Capsule RG 1.99 Predicted % Decrease	=	14.1 (R.G. 1.99, Figure 2)
2nd Capsule Measured % Decrease	=	3.4 (Charpy Curves)
2nd Capsule RG 1.99 Predicted % Decrease	=	17.8 (R.G. 1.99, Figure 2)
Limiting Beltline Plate USE (ESW):		
%Cu	=	0.24
62 EFPY Peak ID Fluence	=	1.34E+18 n/cm^2
62 EFPY 1/4T Fluence	=	9.49E+17 n/cm^2
RG 1.99 Predicted % Decrease	=	21.8 (RG 1.99, Rev. 2, Figure 2)
Adjusted % Decrease	=	N/A (RG 1.99, Rev. 2, Position 2.2)
Comparison of Limiting % Decrease Value to Limit:		
21.8%	≤	**{{ }}**
Therefore, Unit 3 vessel welds are bounded by Equivalent Margin Analysis		

4.2.3 Reactor Vessel Adjusted Reference Temperature (ART) Analyses

TLAA Description:

The ART of the limiting beltline material is used to adjust the P-T limit curves to account for irradiation effects. RG 1.99, Revision 2 (Reference 4.8.27), provides the methodology for determining the ART of the limiting materials. The initial nil-ductility reference temperature, RT_{NDT}, is the temperature at which an unirradiated ferritic steel material changes in fracture characteristics from ductile to brittle behavior. RT_{NDT} is evaluated according to the procedures in the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III, Paragraph NB-2331. Neutron embrittlement increases the RT_{NDT} beyond its initial value.

10 CFR 50, Appendix G (Reference 4.8.8), defines the fracture toughness requirements for the life of the reactor vessel. The shift in the initial RT_{NDT} (ΔRT_{NDT}) is evaluated as the difference in the 30 ft-lb index temperatures from the average Charpy curves measured before and after irradiation. This increase (ΔRT_{NDT}) determines how much higher the vessel temperature must be

raised for the material to continue to act in a ductile manner. The ART is defined as: Initial RT_{NDT} + ΔRT_{NDT} + Margin (Reference 4.8.27).

The ΔRT_{NDT} and ART calculations meet the criteria of 10 CFR 54.3(a). As such, they are TLAAs requiring evaluation for the subsequent period of extended operation.

TLAA Evaluation:

10 CFR 50, Appendix G, requires the determination of ART values for reactor vessel beltline ferritic materials for the life of the plant. The beltline plates, axial welds, and circumferential welds are fabricated from ferritic materials. The beltline also includes the N16 WLI nozzles and welds, which are nickel alloy materials, thus not ferritic. The N16 nozzle penetrations have partial penetration welds, so the 1/4T location along the limiting pressure stress cross-section is located within the surrounding ferritic plate material, so it is appropriate to determine the ART value for these nozzles using the plate material properties. Therefore, the ART values for the N16 nozzles and welds have been determined using the fluence and the limiting material property values (chemistry and initial RT_{NDT}) for the surrounding ferritic plate material. The ART values computed for the N16 nozzles will be used in the development of P-T limit curves that address the applied and residual stresses in the nozzles in conjunction with the appropriate material property values resulting from 80 years of neutron exposure.

As described in Section 4.2.1, 80-year fluence values have been determined for BFN Units 1, 2, and 3 beltline materials using the methodology specified in Regulatory Guide 1.99, Revision 2. The 1/4T and 3/4T fluence values for each location were derived from the plant specific dpa attenuation method described in Regulatory Guide 1.99, Revision 2 (Reference 4.8.27).

- Table 4.2.3-1 provides the Unit 1 50 EFPY 1/4T ART values computed for the beltline plates, axial welds, circumferential welds, N16 nozzle forgings and welds, and Integrated Surveillance Program (ISP) plate and weld material. The N16 nozzle forging and welds are nickel alloy materials, which are not ferritic. However, they are evaluated for ART using the fluence at the nozzle cutout location using the limiting material properties (chemistry and initial RT_{NDT}) from the surrounding plate material.
- Table 4.2.3-2 provides the Unit 2 64 EFPY 1/4T ART values computed for the beltline plates, axial welds, circumferential welds, N16 nozzle forgings and welds, and ISP plate and weld material. The N16 nozzle forging and welds are nickel alloy materials, which are not ferritic. However, they are evaluated for ART using the fluence at the nozzle cutout location using the limiting material properties (chemistry and initial RT_{NDT}) from the surrounding plate material.
  - Table 4.2.3-1 and Table 4.2.3-2 provide 50 and 64 (respectively) EFPY ART values for ISP plate and weld material from BWRVIP-135, Revision 4 data for Unit 1 and 2 (Reference 4.8.47), which supersede plant-specific values where available, as required by BWR ISP procedures. It also includes 50 and 64 EFPY ART values computed for ISP weld materials from BWRVIP-135, Revision 4 (Reference 4.8.47).
- Table 4.2.3-3 provides the Unit 3 62 EFPY 1/4T ART values computed for the beltline plates, axial welds, circumferential welds, N16 nozzle forgings and welds, and ISP plate and weld material. The N16 nozzle forging and welds are nickel alloy materials, which are not ferritic. However, they are evaluated for ART using the fluence at the nozzle cutout location using the limiting material properties (chemistry and initial RT_{NDT}) from the surrounding plate material.

The limiting locations are listed below:

Unit 1 ART Results:

- The limiting ART value for the Unit 1 reactor vessel at 50 EFPY is 146.9ºF, which was computed for the Lower to Lower- Intermediate Girth Weld, WF154.
- The limiting ART value for the Unit 1 N16 WLI nozzle at 50 EFPY is 40.5ºF, which was computed based upon the material properties of the surrounding Lower-Intermediate Shell plate heat C2884-2 (since the nozzle forging material is nickel alloy material that does not require evaluation).
- The limiting ART value for the Unit 1 ISP plate material from BWRVIP-135, Revision 3 at 50 EFPY is 103.7ºF, computed for plate heat A0981-1.

Unit 2 ART Results:

- The limiting ART value for the Unit 2 reactor vessel at 64 EFPY is 143.0ºF, which was computed for the Axial Welds.
- The limiting ART value for the Unit 2 N16 WLI nozzle at 64 EFPY is 33.5, which was computed based upon the material properties of the surrounding Lower-Intermediate Shell plate heat C2467-1 (since the nozzle forging material is nickel alloy material that does not require evaluation).
- The limiting ART value for the Unit 2 ISP plate material from BWRVIP-135, Revision 3 at 64 EFPY is 71.9ºF, computed for plate heat A0981-1.

Unit 3 ART Results:

- The limiting ART value for the Unit 3 reactor vessel at 62 EFPY is 142.0ºF, which was computed for the Axial Welds.
- The limiting ART value for the Unit 3 N16 WLI nozzle at 62 EFPY is 15.0ºF, which was computed based upon the material properties of the surrounding Lower-Intermediate Shell plate heat C3201-2 (since the nozzle forging material is nickel alloy material that does not require evaluation).
- The limiting ART value for the Unit 3 ISP plate material from BWRVIP-135, Revision 3 at 62 EFPY is 87.4ºF, computed for plate heat A0981-1.

The above ART values (at depth of 1/4T) of the limiting beltline locations at 80 years remain below 200°F, which is the Nil-Ductility Transition (RT_{NDT}) limit specified in NRC Regulatory Guide 1.99, Revision 2, Section 3.

<u>TLAA Disposition:</u>

10 CFR 54.21(c)(1)(ii) - The 80-year reactor vessel ART analyses have been projected through the subsequent period of extended operation.

Table 4.2.3-1, BFN Unit 1 - 50 EFPY 1/4T Adjusted Reference Temperature (ART) Values for Reactor Vessel Materials

Beltline I.D.	Component	Heat No.	% Cu	% Ni	CF	Initial RT_{NDT} (°F)	Fluence at 1/4T (n/cm^2)	Fluence Factor f	ΔRT_{NDT} (°F)	$\sigma\Delta$ (°F)	σi (°F)	Margin (°F)	ART at 1/4T (°F)
Plates													
Lower Shell #1	6-127-1	A0999-1	0.14	0.6	100.0	-20	7.69E+17	0.366	36.6	17	0	34.0	50.6
Lower Shell #2	6-127-2	B5864-1	0.15	0.44	101.2	-20	7.69E+17	0.366	37.1	17	0	34.0	51.1
Lower Shell #3	6-127-4	A1009-1	0.14	0.5	95.5	-10	7.69E+17	0.366	35.0	17	0	34.0	59.0
Lower Intermediate Shell #1	6-139-19	C2884-2	0.12	0.53	81.6	14	9.45E+17	0.406	33.1	16.6	0	33.1	80.2
Lower Intermediate Shell #2	6-139-20	C2868-2	0.09	0.48	58.0	30	9.45E+17	0.406	23.5	11.8	0	23.5	77.1
Lower Intermediate Shell #3	6-139-21	C2753-1	0.08	0.5	51.0	2	9.45E+17	0.406	20.7	10.3	0	20.7	43.4
Welds													
Axial Welds	ESW	-	0.24	0.37	140.6	23.1	7.87E+17	0.371	52.1	26.0	13	58.2	133.4
Lower to Lower-Intermediate Girth Weld	WF154	406L44	0.27	0.6	184.0	20	7.69E+17	0.366	67.4	28.0	10	59.5	146.9
Nozzles													
N16 Water Level Instrument Nozzle	Forging & Weld[1]	Inconel	0.12	0.53	81.6	14	1.82E+17	0.162	13.2	6.6	0	13.2	40.5
ISP													
Integrated Surveillance Program	Plate[2]	A0981- 1	0.14	0.55	97.8	30	9.45E+17	0.406	39.7	17	0	34.0	103.7
Integrated Surveillance Program	Weld[3]	SSP 406L44	0.29	0.69	279.5	23.1	7.69E+17	0.366	102.4	28.0	10	59.5	185.0

Table 4.2.3-1 Notes:

1. N16 nozzle material properties are those for the bounding adjacent shell plate, as the nozzle and weld are non-ferritic material.
2. The ISP plate heat does not match the target plate heat, and the surveillance data are provided for information only.
3. The ISP weld heat does match the target weld heat. The fitted CF of 311.3°F (Reference 4.8.47, Table B-15-6) is higher than the RG 1.99 table CF of 204.95°F. It is adjusted according to RG 1.99 as 311.3°*(184/204.95) =279.5°F. The full margin term is used, as the scatter in the surveillance data exceeds credibility criteria.

Table 4.2.3-2, BFN Unit 2 - 64 EFPY 1/4T Adjusted Reference Temperature (ART) Values for Reactor Vessel Materials

Beltline I.D.	Component	Heat No.	% Cu	% Ni	CF	Initial RT_{NDT} (°F)	Fluence at 1/4T (n/cm^2)	Fluence Factor f	ΔRT_{NDT} (°F)	σΔ (°F)	σi (°F)	Margin (°F)	ART at 1/4T (°F)
Plates													
Lower Shell #1	6-127-14	C2467-2	0.16	0.52	112.4	-20	9.48E+17	0.406	45.7	17	0	34.0	59.7
Lower Shell #2	6-127-15	C2463-1	0.17	0.48	116.8	-20	9.48E+17	0.406	47.5	17	0	34.0	61.5
Lower Shell #3	6-127-17	C2460-2	0.13	0.51	88.3	0	9.48E+17	0.406	35.9	17	0	34.0	69.9
Lower Intermediate Shell #1	6-127-6	A0981-1	0.14	0.55	97.8	-10	1.19E+18	0.453	44.2	17	0	34.0	68.2
Lower Intermediate Shell #2	6-127-16	C2467-1	0.16	0.52	112.4	-10	1.19E+18	0.453	50.9	17	0	34.0	74.9
Lower Intermediate Shell #3	6-127-20	C2849-1	0.11	0.5	73.0	-10	1.19E+18	0.453	33.0	16.5	0	33.0	56.1
Welds													
Axial Welds	ESW	-	0.24	0.37	140.6	23.1	9.84E+17	0.414	58.1	28.0	13	61.7	143.0
Lower to Lower-Intermediate Girth Weld	-	D55733	0.09	0.65	116.8	-40	9.48E+17	0.406	47.4	23.7	0	47.4	54.9
Nozzles													
N16 Water Level Instrument Nozzle	Forging & Weld[1]	Inconel	0.16	0.52	112.4	-10	2.42E+17	0.193	21.7	10.9	0	21.7	33.5
ISP													
Integrated Surveillance Program	Plate[2]	A0981-1	0.14	0.55	143.4	-10	1.19E+18	0.453	64.9	8.5	0	17.0	71.9

Table 4.2.3-2, BFN Unit 2 - 64 EFPY 1/4T Adjusted Reference Temperature (ART) Values for Reactor Vessel Materials (Continued)

Beltline I.D.	Component	Heat No.	% Cu	% Ni	CF	Initial RT_{NDT} (°F)	Fluence at 1/4T (n/cm^2)	Fluence Factor f	ΔRT_{NDT} (°F)	$\sigma\Delta$ (°F)	σi (°F)	Margin (°F)	ART at 1/4T (°F)
Integrated Surveillance Program	Weld[3]	BF2 ESW	0.2	0.33	285.8	23.1	9.84E+17	0.414	118.2	14.0	13	38.2	179.5

Table 4.2.3-2 Notes:

1. N16 nozzle material properties are those for the bounding adjacent shell plate, as the nozzle and weld are non-ferritic material.
2. The ISP plate heat does not match the target plate heat; however, the ISP plate does match a heat in the Unit 2 beltline. Therefore, the ISP plate data is considered in determination of the ART for the matching heat. The surveillance data are credible, and a reduced margin term is used.
3. The ISP weld heat is assumed to match the target weld heat, because the heat numbers for the BFN Unit 2 axial ESW welds are not specified in plant documentation. The fitted CF of 244.5°F (Reference 4.8.47, Table B-1-6) is adjusted based on the difference in chemistry between the surveillance weld and vessel weld to be 244.5*(140.55/120.25) =285.8°F. The surveillance data are credible, and a reduced margin term is used.

Table 4.2.3-3, BFN Unit 3 - 62 EFPY 1/4T Adjusted Reference Temperature (ART) Values for Reactor Vessel Materials

Beltline I.D.	Component	Heat No.	% Cu	% Ni	CF	Initial RT_{NDT} (°F)	Fluence at 1/4T (n/cm^2)	Fluence Factor f	ΔRT_{NDT} (°F)	$\sigma\Delta$ (°F)	σi (°F)	Margin (°F)	ART at 1/4T (°F)
Plates													
Lower Shell #1	6-145-4	C3222-2	0.15	0.52	105.6	10	9.16E+17	0.400	42.2	17	0	34.0	86.2
Lower Shell #2	6-145-7	C3213-1	0.13	0.58	90.4	-20	9.16E+17	0.400	36.1	17	0	34.0	50.1
Lower Shell #3	6-145-12	C3217-2	0.14	0.66	101.5	-4	9.16E+17	0.400	40.6	17	0	34.0	70.6
Lower Intermediate Shell #1	6-145-1	C3201-2	0.13	0.6	91.0	-20	1.14E+18	0.444	40.4	17	0	34.0	54.4
Lower Intermediate Shell #2	6-145-2	C3188-2	0.1	0.48	65.0	-20	1.14E+18	0.444	28.8	14.4	0	28.8	37.7
Lower Intermediate Shell #3	6-145-6	B7267-1	0.13	0.51	88.3	-20	1.14E+18	0.444	39.2	17	0	34.0	53.2
Welds													
Axial Welds	ESW	-	0.24	0.37	140.6	23.1	9.49E+17	0.406	57.1	28.0	13	61.7	142.0
Lower to Lower-Intermediate Girth Weld	-	D55733	0.09	0.66	117.1	-40	9.16E+17	0.400	46.8	23.4	0	46.8	53.6
Nozzles													
N16 Water Level Instrument Nozzle	Forging & Weld[1]	Inconel	0.13	0.6	91.0	-20	2.40E+17	0.192	17.5	8.8	0	17.5	15.0
ISP													
Integrated Surveillance Program	Plate[2]	A0981-1	0.14	0.55	97.8	10	1.14E+18	0.444	43.4	17	0	34.0	87.4
Integrated Surveillance Program	Weld[3]	BF2 ESW	0.2	0.33	120.3	23.1	9.49E+17	0.406	48.9	24.4	13	55.4	127.3

Table 4.2.3-3 Notes:

1. N16 nozzle material properties are those for the bounding adjacent shell plate, as the nozzle and weld are non-ferritic material.
2. The ISP plate heat does not match the target plate heat. The surveillance data are provided for information only.
3. The ISP weld heat does not match the target weld heat. The surveillance data are provided for information only.

4.2.4 Reactor Vessel Pressure-Temperature (P-T) Limits

TLAA Description:

10 CFR 50 Appendix G requires that the reactor vessel be maintained within established P-T limits, including heatup and cooldown operations. These limits specify the minimum acceptable reactor coolant temperature as a function of reactor pressure. As the reactor vessel is exposed to increased neutron irradiation over time, its fracture toughness is reduced. The P-T limits must account for the change in material properties due to anticipated reactor vessel fluence.

The currently licensed P-T limit curves are located in the BFN Units 1, 2, and 3 Technical Specification 3.4.9, Reactor Coolant System (RCS) Pressure and Temperature Limits (Reference 4.8.18). The currently licensed BFN P-T limit curves were developed for up to 38 EFPY for Unit 1, 48 EFPY for Unit 2, and 54 EFPY for Unit 3. Since the P-T limit curves are based on EFPY projections for the currently approved 60-year operating term, the P-T limit curves have been identified as TLAAs requiring evaluation for the subsequent period of extended operation.

TLAA Evaluation:

In accordance with NUREG-2192 (Reference 4.8.2), Section 4.2.2.1.4, for plants that have the P-T limits located in the limiting conditions for operation (LCOs) of the Technical Specifications (TS), updated P-T limits for the subsequent period of extended operation need not be submitted as part of the SLRA. However, the updated P-T limits for the subsequent period of operation must be established and completed using the applicable TS change process for updating the P-T limit curves prior to the plant's entry into the subsequent period of extended operation. The 10 CFR 50.90 process will ensure that the P-T limits for the subsequent period of extended operation will be updated prior to expiration of the P-T limits for the current period of operation. The analyses supporting the P-T curves will consider all locations within the reactor coolant pressure boundary as they do in the current P-T curves. Maintenance of the P-T limits during the subsequent period of extended operation will be managed using the 10 CFR 50.90 process as described above.

Revised P-T limits will be prepared and submitted to the NRC for approval prior to exceeding the current 38 EFPY limits for Unit 1, 48 EFPY limits for Unit 2, and 54 EFPY limits for Unit 3.

TLAA Disposition:

10 CFR 54.21(c)(1)(iii) - The effects of aging on the intended function(s) of the reactor vessels will be adequately managed through the subsequent period of extended operation using the 10 CFR 50.90 process for changes to P-T limits located in TS LCOs.

4.2.5 Reactor Vessel Circumferential Weld Failure Probability Analyses

TLAA Description:

BFN has previously applied for and been granted relief from reactor vessel circumferential weld inspections for the Unit 2 reactor vessel and for the Unit 3 reactor vessel, as described in the NRC SE dated March 14, 2012 (Reference 4.8.19). BFN also applied for relief and have been granted relief from reactor vessel circumferential weld inspections for the Unit 1 reactor vessel, as described in NRC SE dated February 17, 2016 (Reference 4.8.20).

BWRVIP-05 (Reference 4.8.21) provides the technical basis for the elimination of ASME Code, Section XI examination of reactor vessel circumferential welds and the reduction of examination of reactor vessel axial welds for BWRs. The scope and evaluation for BWRVIP-05 was limited to 40 years of plant operation.

Subsequently, BWRVIP-329-A (Reference 4.8.22) and the associated NRC SER (Reference 4.8.23) provide additional technical basis for reduction in inspection of reactor vessel circumferential welds and an assessment of axial weld integrity for extended operations of up to 80 years. BWRVIP-329-A (Section 5, Implementation) provides criteria for applicability based on plant-specific data. The circumferential weld examination relief analyses meet the requirements of 10 CFR 54.3(a). As such, they have been identified as TLAAs requiring evaluation for the subsequent period of extended operation.

<u>TLAA Evaluation:</u>

80-year unit-specific fluence values have been projected for each circumferential weld as described in Section 4.2.1.1. Using the inside surface (0T) fluence values for these welds, the BFN end of interval (EOI) maximum reference temperature (RT_{MAX}) values have been determined for the limiting circumferential welds within the beltline for each unit. Additional EOI RT_{MAX} values were determined for the limiting reactor vessel plate material for each unit because it was determined that flaws can also develop within the weld fusion zone between the weld and base metal.

Table 4.2.5-1, Table 4.2.5-2, and Table 4.2.5-3 calculate the limiting maximum reference temperatures, RT_{MAX}, for ID surface values (i.e., 0T), which were calculated using unit-specific neutron fluence, material chemistry (copper content, nickel content, and chemistry factor), and $RT_{NDT(U)}$ for the BFN reactor vessel plates and circumferential welds. The EOI for BFN are unit-specific based on 50 EFPY for Unit 1, 64 EFPY for Unit 2, and 62 EFPY for Unit 3. The **{{ }}** Limiting RT_{MAX}(°F) value is **{{ }}** for the limiting plate and limiting circumferential weld. The EOI RT_{MAX} values for all BFN reactor vessel plates and circumferential welds meet the acceptability criteria for limiting plates and circumferential welds in BWRVIP-329-A.

Request for relief from circumferential weld examination will be made in accordance with 10 CFR 50.55a for NRC review and approval. The plant-specific information described above demonstrates that, at the end of the subsequent period of extended operation, the BFN Units 1, 2, and 3 circumferential beltline weld materials meet the applicability criteria for limiting plates and circumferential welds in BWRVIP-329-A.

<u>TLAA Disposition:</u>

10 CFR 54.21(c)(1)(iii) - The Units 1, 2, and 3 reactor vessel circumferential weld failure probability analyses have been projected through the subsequent period of extended operation. Relief from inspection of circumferential welds during the subsequent period of extended operation will be requested in accordance with the 10 CFR 50.55a process.

Table 4.2.5-1, BFN Unit 1 Circumferential Weld Probability Analyses

Parameter	Unit 1 Limiting Plate	Unit 1 Limiting Circumferential Weld
Component No.	Lower Intermediate Shell #1 6-139-19	Lower to Lower-Intermediate Girth Weld WF154
Heat / Lot Identification Number	C2884-2	406L44
Copper Content (wt. %)	0.12	0.27
Nickel Content (wt. %)	0.53	0.6
Chemistry Factor (CF) (°F)	81.6	184.0
50 EFPY EOI Neutron Fluence (f) (n/cm^2)	1.34E+18	1.09E+18
$RT_{NDT(U)}$ (°F)	14	20
EOI ΔRT_{NDT} (°F)	39.0	79.9
EOI RT_{MAX} (°F)	87.0[1]	159.4[2]

Notes:

1. The EOI RT_{MAX} plate value of 110.7 °F for BFN Unit 1 from the ISP is higher than the limiting plate from the BFN Unit 1 reactor vessel and meets the limiting RT_{MAX} acceptability criteria for limiting plate in BWRVIP-329-A.
2. EOI RT_{MAX} weld value of 204.0 °F for BFN Unit 1 from the ISP higher than the limiting circumferential weld from the BFN Unit 1 reactor vessel and meets the limiting RT_{MAX} acceptability criteria for limiting circumferential welds in BWRVIP-329-A.

Table 4.2.5-2, BFN Unit 2 Circumferential Weld Probability Analyses

Parameter	Unit 2 Limiting Plate	Unit 2 Limiting Circumferential Weld
Component No.	Lower Intermediate Shell #2 6-127-16	Lower to Lower-Intermediate Girth Weld
Heat / Lot Identification Number	C2467-1	D55733
Copper Content (wt. %)	0.16	0.09
Nickel Content (wt. %)	0.52	0.65
Chemistry Factor (CF) (°F)	112.4	116.8
64 EFPY EOI Neutron Fluence (f) (n/cm^2)	1.69E+18	1.34E+18
$RT_{NDT(U)}$ (°F)	-10	-40
EOI ΔRT_{NDT} (°F)	59.6	55.8
EOI RT_{MAX} (°F)	83.6	71.6[1]

Notes:

1. The EOI RT_{MAX} plate value of 200.2 °F for BFN Unit 2 from the ISP is higher than the circumferential weld from the BFN Unit 2 reactor vessel and meets the limiting RT_{MAX} acceptability criteria for limiting circumferential welds in BWRVIP-329-A.

Table 4.2.5-3, BFN Unit 3 Circumferential Weld Probability Analyses

Parameter	Unit 3 Limiting Plate	Unit 3 Limiting Circumferential Weld
Component No.	Lower Shell #1 6-145-4	Lower to Lower-Intermediate Girth Weld
Heat / Lot Identification Number	C3222-2	D55733
Copper Content (wt. %)	0.15	0.09
Nickel Content (wt. %)	0.52	0.66
Chemistry Factor (CF) (°F)	105.6	117.1
62 EFPY EOI Neutron Fluence (f) (n/cm^2)	1.29E+18	1.29E+18
$RT_{NDT(U)}$ (°F)	10	-40
EOI ΔRT_{NDT} (°F)	49.6	55.0
EOI RT_{MAX} (°F)	93.6[1]	70.0[2]

Notes:

1. The EOI RT_{MAX} plate value of 95.0 °F for BFN Unit 3 from the ISP is higher than the limiting plate from the BFN Unit 3 reactor vessel and meets the limiting RT_{MAX} acceptability criteria for limiting plate in BWRVIP-329-A.
2. EOI RT_{MAX} weld value of 142.3 °F for BFN Unit 3 from the ISP is higher than the limiting circumferential weld from the BFN Unit 3 reactor vessel and meets the limiting RT_{MAX} acceptability criteria for limiting circumferential welds in BWRVIP-329-A.

4.2.6 Reactor Vessel Axial Weld Failure Probability Analyses

TLAA Description:

BWRVIP-05 (Reference 4.8.21) provides the technical basis for the elimination of the ASME Code, Section XI examination of reactor vessel circumferential welds and the reduction of examination of reactor vessel axial welds for BWRs. The scope and evaluation of BWRVIP-05 was limited to 40 years of plant operation.

Subsequently, BWRVIP-329-A (Reference 4.8.22) and the associated NRC SE (Reference 4.8.23) provide additional technical basis for an assessment of axial weld integrity for extended operations of up to 80 years. BWRVIP-329-A (Reference 4.8.22, Section 5, Implementation) provides criteria for applicability based on plant-specific data. Since these failure probability assessments are applicable to BFN Units 1, 2, and 3, they are identified as TLAAs requiring evaluation through the subsequent period of extended operation.

TLAA Evaluation:

80-year unit-specific fluence values have been projected for each axial weld as described in Section 4.2.1.1. Using the inside surface (0T) fluence values for these welds, the BFN EOI

RT_{MAX} values have been determined for the limiting axial welds within the beltline for each unit. Additional EOI RT_{MAX} values were determined for the limiting reactor vessel plate material for each unit because it was determined that flaws can also develop within the weld fusion zone between the weld and base metal (Reference 4.8.22).

Table 4.2.6-1, Table 4.2.6-2, and Table 4.2.6-3 calculate the limiting maximum reference temperatures, RT_{MAX}, for ID surface values (i.e., 0T), which were calculated using unit-specific neutron fluence, material chemistry (copper content, nickel content, and chemistry factor), and $RT_{NDT(U)}$ for the BFN reactor vessel plates and axial welds. The EOI for BFN are unit-specific based on 50 EFPY for Unit 1, 64 EFPY for Unit 2, and 62 EFPY for Unit 3. The **{{ }}**Limiting RT_{MAX}(°F) value is **{{ }}** for the limiting plate and **{{ }}** for the limiting axial weld. The EOI RT_{MAX} values for all BFN reactor vessel plates and axial welds meet the acceptability criteria for limiting plates and axial welds in BWRVIP-329-A (Reference 4.8.22).

<u>TLAA Disposition:</u>

10 CFR 54.21(c)(1)(ii) - The Units 1, 2, and 3 reactor vessel axial weld failure probability analyses have been projected through the subsequent period of extended operation.

Table 4.2.6-1, BFN Unit 1 Axial Weld Probability Analyses

Parameter	Unit 1 Limiting Plate	Unit 1 Limiting Axial Weld
Component No.	Lower Intermediate Shell #1 6-139-19	Axial Welds ESW
Heat / Lot Identification Number	C2884-2	-
Copper Content (wt. %)	0.12	0.24
Nickel Content (wt. %)	0.53	0.37
Chemistry Factor (CF) (°F)	81.6	140.6
50 EFPY EOI Neutron Fluence (f) (n/cm^2)	1.34E+18	1.11E+18
$RT_{NDT(U)}$ (°F)	14	23.1
EOI ΔRT_{NDT} (°F)	39.0	61.6
EOI RT_{MAX} (°F)	87.0[1]	146.4[2]

Notes:

1. The EOI RT_{MAX} plate value of 110.7 °F for BFN Unit 1 from the ISP is higher than the limiting plate from the BFN Unit 1 reactor vessel and meets the limiting RT_{MAX} acceptability criteria for limiting plate in BWRVIP-329-A.
2. EOI RT_{MAX} weld value of 204.0 °F for BFN Unit 1 from the ISP is higher than the limiting axial weld from the BFN Unit 1 reactor vessel and meets the limiting RT_{MAX} acceptability criteria for limiting axial welds in BWRVIP-329-A.

Table 4.2.6-2, BFN Unit 2 Axial Weld Probability Analyses

Parameter	Unit 2 Limiting Plate	Unit 2 Limiting Axial Weld
Component No.	Lower Intermediate Shell #2 6-127-16	Axial Welds ESW
Heat / Lot Identification Number	C2467-1	-
Copper Content (wt. %)	0.16	0.24
Nickel Content (wt. %)	0.52	0.37
Chemistry Factor (CF) (°F)	112.4	140.6
64 EFPY EOI Neutron Fluence (f) (n/cm^2)	1.69E+18	1.39E+18
$RT_{NDT(U)}$ (°F)	-10	23.1
EOI ΔRT_{NDT} (°F)	59.6	68.3
EOI RT_{MAX} (°F)	83.6	153.1[1]

Notes:

1. The EOI RT_{MAX} plate value of 200.2 °F for BFN Unit 2 from the ISP is higher than the axial weld from the BFN Unit 2 reactor vessel and meets the limiting RT_{MAX} acceptability criteria for limiting axial welds in BWRVIP-329-A.

Table 4.2.6-3, BFN Unit 3 Axial Weld Probability Analyses

Parameter	Unit 3 Limiting Plate	Unit 3 Limiting Axial Weld
Component No.	Lower Shell #1 6-145-4	Axial Welds ESW
Heat / Lot Identification Number	C3222-2	-
Copper Content (wt. %)	0.15	0.24
Nickel Content (wt. %)	0.52	0.37
Chemistry Factor (CF) (°F)	105.6	140.6
62 EFPY EOI Neutron Fluence (f) (n/cm^2)	1.29E+18	1.34E+18
$RT_{NDT(U)}$ (°F)	10	23.1
EOI ΔRT_{NDT} (°F)	49.6	67.2
EOI RT_{MAX} (°F)	93.6[1]	152.0

Notes:

1. The EOI RT_{MAX} plate value of 95.0 °F for BFN Unit 3 from the ISP is higher than the limiting plate from the BFN Unit 1 reactor vessel and meets the limiting RT_{MAX} acceptability criteria for limiting plate in BWRVIP-329-A.

4.2.7 Reactor Vessel Reflood Thermal Shock Analysis

TLAA Description:

10 CFR 50 Appendix A, General Design Criterion 31 requires that the reactor coolant pressure boundary of a light water reactor be designed such that it possesses adequate margin against non-ductile failure for all postulated conditions.

For BWRs designed by General Electric, this requirement was demonstrated both by development of P-T Limit Curves, which are addressed in SLRA Section 4.2.4, and by reference to generic fracture analyses that evaluates the effects of the limiting LOCA event. The acceptance criterion used in these analyses is that the crack driving force for postulated flaws in the reactor vessel, K_I, is less than the applicable material resistance to fracture, K_{IC}.

Since this analysis was identified as a TLAA for the initial license renewal project and validated for 60 years, it has been identified as a TLAA that must be re-evaluated for the subsequent period of extended operation.

TLAA Evaluation:

The generic fracture analyses evaluations addressed the reactor vessel shell only. The effect of nozzles in the beltline is not specifically addressed. The 80-year fluence values described in Section 4.2.1 demonstrated that the N16 nozzle is within the beltline with a fluence above 1.0E+17 n/cm^2, so an analysis of the N16 nozzle is necessary to augment reactor vessel shell analyses to demonstrate adequate margin against non-ductile failure for all beltline materials during the subsequent period of extended operation.

Nozzles with fluence below 1.0E+17 n/cm^2 (E > 1 MeV) do not require evaluation for the effects of neutron embrittlement (including effects on K_{IC}, fracture toughness). Fluences above 1.0E+17 n/cm^2 would require additional analyses to account for the effects of neutron embrittlement.

Updated 80-year fracture mechanics evaluations have been performed for the reflood thermal shock event using plant-specific reactor vessel data for BFN Units 1, 2, and 3. The limiting ART values for Unit 1, 2, and 3 beltline materials, based upon the 80 year fluence projections, have been used in these fracture mechanics analyses (refer to Table 4.2.7-1). The ART is the RT_{NDT} value adjusted to account for increased fluence during the life of the vessel.

Table 4.2.7-1, BFN Limiting ART Values for Reactor Vessel Shell/Plates

Unit	EFPY for 80 Years of Operation	Limiting 0T ART (°F)
Unit 1	50 EFPY	204.0
Unit 2	64 EFPY	200.2
Unit 3	62 EFPY	152.0

For all beltline materials, a bounding evaluation is performed in which the limiting stresses and material properties for the BFN reactor vessel are used. The beltline shells (plates and welds) and the beltline nozzles are considered separately. The K_{IC} value can be determined by the RT_{NDT} at a desired temperature of operation:

$K_{IC} = 33.2 + 20.734 \exp(0.02\,(T - ART))$

The fracture toughness curves in ASME XI A-4200 are truncated above 200 ksi-in$^{1/2}$ (the assumed upper-shelf toughness value) mainly due to the difficulty of measuring valid plane strain toughness data beyond this toughness value. To be consistent with the Ranganath analysis, and for conservatism, a K_{IC} of **{{   }}** ksi-in$^{1/2}$ is used. The allowable K_I value for emergency and faulted conditions is $K_{IC}/\sqrt{2}$. For the current assessment, **{{ }}** ksi-in$^{1/2}$ is the available fracture toughness (per the rules of IWB-3612).

The maximum $K_{Iapplied}$ in the vessel at any time during the transient is 105 ksi-in$^{1/2}$. The crack stability analysis for the beltline shells shows that $K_{Iapplied}$ is less than the allowable value by a margin of 1.35 for all three BFN units.

The maximum stress intensity factor calculated for the N16 nozzle transient is 83.99 ksi-in$^{1/2}$ at 1/4T. The limiting ART of the N16 nozzle (adjacent shell plates) is 47.3°F, 43.7°F, and 23.3°F for Units 1, 2, and 3, respectively. A conservative value for temperature at the surface is 280°F. Compared against the allowable fracture toughness (**{{   }}** ksi-in$^{1/2}$), there is a margin of **{{   }}** applied to the nozzle, per ASME Code limits, for all three BFN units.

All beltline materials in the BFN reactor vessel are shown to satisfy the acceptance criteria of no crack initiation, for postulated flaw sizes less than or equal to the flaw sizes acceptable, without evaluation, in ASME XI IWB-3500 and considering operation through the end of the subsequent period of extended operation, 50 EFPY, 64 EFPY, and 62 EFPY for Units 1, 2, and 3, respectively. These analyses confirm that adequate margin against non-ductile failure of the BFN RPV and the N16 nozzle is maintained for the design basis LOCA transients through the end of the subsequent period of extended operation.

<u>TLAA Disposition:</u>

10 CFR 54.21(c)(1)(ii) - The reactor vessel reflood thermal shock analysis has been projected through the subsequent period of extended operation.

4.2.8 Core Shroud Reflood Thermal Shock Analysis

<u>TLAA Description:</u>

Neutron irradiation embrittlement may affect the ability of core shroud to withstand a low-pressure coolant injection thermal shock transient. The reactor vessel core shrouds were analyzed for a low-pressure coolant injection reflood thermal shock transient considering the embrittlement effects of 40-year neutron irradiation exposure (32 EFPY). This analysis was re-evaluated for the initial license renewal project and validated for a 60-year extended operating term.

Since this analysis was identified as a TLAA for the initial license renewal project and validated for 60 years, it has been identified as a TLAA that must be re-evaluated for the subsequent period of extended operation.

<u>TLAA Evaluation:</u>

As described in the LRA, the RPV core shroud was previously evaluated for a low-pressure coolant injection reflood thermal shock transient considering the embrittlement effects of 60-year exposure (54 EFPY) for all 3 units. The core shroud receives the maximum irradiation on the inside surface opposite the midpoint of the fuel centerline. The total integrated neutron exposure at end-of-life at the inside surface of the shroud for 60 years was projected to be 5.34E+21 n/cm^2 (E > 1 MeV).

The maximum thermal shock stress in this region is 155,700 psi which is equivalent to 0.57% strain. This strain range of 0.57% was calculated at the midpoint of the shroud, the zone of highest neutron irradiation. The calculated strain range of 0.57% represents a considerable margin of safety relative to measured values of percent elongation for annealed Type 304 stainless steel irradiated to 8E+21 n/cm^2 (E > 1 MeV). The measured value of percent elongation for stainless steel weld metal is 4% for a temperature of 297°C (567°F) with a neutron fluence of 8E+21 n/cm^2 (E > 1 MeV), while the average value of base metal at 290°C (554°F) is 20% (Reference 4.8.29).

As documented in BWRVIP-66 Section 3.1 (Reference 4.8.29), the weld metal subjected to testing exhibited a 4% elongation to failure at the highest fluence point. The highest fluence sample specimen (6.9E+21 n/cm^2) was measured for % area reduction (%RA) as discussed in the BFN SE (Reference 4.8.30). The resulting %RA was 52.5% at the highest fluence location. This %RA is significantly greater than the linear strain analyzed for thermal shock. The linear strain required to achieve this reduction in area is bound by the test data of 4% elongation at failure at the most limiting weld location, and therefore, the elongation at failure values are used in the following assessment for 80-year operating period. The measured value of elongation bounds the calculated thermal shock strain amplitude of 0.57 percent, and thus, the calculated thermal shock strain at the most irradiated location is acceptable considering the embrittlement effects for the period of extended operation. Therefore, thermal shock effects on the shroud at the point of highest irradiation level will not jeopardize the proper functioning of the shroud following the DBA. The reflood strain does not pose any concern for the currently licensed operating period (i.e., period of extended operation).

As discussed above, the %RA method of determining strain is bounded by the linear strain results performed for tensile specimens. Therefore, this assessment is based on the linear strain values of 0.57% and exclude the %RA values. 80-year RAMA fluence projections were prepared for BFN Units 1, 2, and 3 for selected reactor vessel internal components (Section 4.2.1.2). This included fluence projections for the core shroud horizontal and vertical welds.

The 80-year fluence for the most irradiated point on the core shroud was calculated to be 2.43E+21 n/cm^2 (E > 1 MeV) for Unit 1, 2.61E+21 n/cm^2 (E > 1 MeV) for Unit 2, and 2.56E+21 n/cm^2 (E > 1 MeV) for Unit 3. This can be compared to the test data for control blade handles at 8E+21 n/cm^2 (E > 1 MeV) described in Reference 4.8.29. The lowest measured value of percent elongation for stainless steel weld metal is 4% for a temperature of 297°C (567°F) with a neutron fluence of 8E+21 n/cm^2 (E > 1 MeV), while the average value of base metal at 290°C (554°F) is 20% (Reference 4.8.29).

Because the measured value of elongation bounds the calculated thermal shock strain amplitude of 0.57%, the calculated thermal shock strain at the most irradiated location is acceptable considering the loss of ductility effects for an 80-year operating period.

TLAA Disposition:

10CFR54.21(c)(1)(ii) - The reactor vessel core shroud reflood thermal shock analyses have been projected to the end of the subsequent period of extended operation.

4.2.9 Core Plate Hold-Down Bolt Loss of Preload Analysis

TLAA Description:

The reactor vessel core plate is attached to the core support structure by 34 stainless steel hold-down bolts arranged along the rim of the plate. The bolts were preloaded during initial installation but are subject to stress relaxation (loss of preload) because of irradiation effects. The stress state of these bolts was evaluated as part of the analysis performed by GEH to prepare BWRVIP-25 Revision 0, “BWR Vessel and Internals Project BWR Core Plate Inspection and Flaw Evaluations Guidelines” (Reference 4.8.32).

As described in the SE (Reference 4.8.33) to BWRVIP-25, “BWR Core Plate Inspection and Flaw Evaluation Guidelines,” plants must consider relaxation of the rim hold down bolts as a TLAA issue. Since BFN has not installed core plate wedges, the loss of preload must be considered in the TLAA evaluation.

TLAA Evaluation:

As described in Section 4.2.1.2, 80-year RAMA fluence projections were prepared for BFN Units 1, 2, and 3 for selected reactor vessel internal components. This included fluence projections for all core plate hold-down bolts for each unit (refer to Table 4.2.9-1). These fluence projections demonstrate acceptable bolt relaxation over an 80-year period.

Table 4.2.9-1, BFN Core Support Plate Hold-down Bolt Bounding Fast Neutron Fluence (n/cm^2)

Unit 1	Unit 2	Unit 3
50 EFPY	**64 EFPY**	**62 EFPY**
1.16E+20	1.41E+20	1.39E+20

A plant-specific evaluation performed per BWRVIP-25 Appendix A (Reference 4.8.32) and taking into considering the preload relaxation due to thermal effects and fluence of 5E+19 n/cm^2 at 60 years of plant life demonstrated the BFN core plate bolts met the ASME allowable stresses for the most limiting plant-specific load combinations and loads. For SLR, an analysis of the core plate rim hold-down bolts was assessed per the BWRVIP-25 Revision 1-A, Appendix I (Reference 4.8.31) guidance. The evaluation has been projected to the end of the subsequent period of extended operation (from bounding fluence of 5E+19 n/cm^2 for extended operation to 1.41E+20 n/cm^2 for subsequent period of extended operation). The analysis concluded that the criteria of BWRVIP-25 Revision 1-A were satisfied and justifies the elimination of the core plate bolt inspections at BFN during the subsequent period of extended operation.

TLAA Disposition:

10 CFR 54.21(c)(1)(ii) - The core plate hold-down bolt loss of preload analysis has been projected to the end of the subsequent period of extended operation.

4.2.10 Jet Pump Slip Joint Repair Clamp Loss of Preload Analysis

TLAA Description:

Jet pump slip joint repair clamps have been designed and installed on jet pumps in BFN Units 1 and 2 to minimize slip joint vibration and wear of the jet pump assemblies. No slip joint repair clamps are installed on Unit 3. Three slip joint repair clamps remain on Unit 1, and eight remain on Unit 2. The clamps apply a lateral preload to the slip joint, between the exit end of the inlet-mixer and the entrance end of the diffuser.

The design specification for the repair clamp states that the fluence criteria analyzed for the slip joint clamp is 3.02E+18 n/cm^2 for the 40-year design life of the clamp. The specification requires the design to account for the effect of fluence on the properties of the slip joint materials for the design life of the clamp. The structural evaluation states that the “cold” bolt preload is 550 pounds at 100ºF, the initial “hot” preload at 550ºF is 500 pounds, and the minimum, end-of-life preload is 350 pounds at 550ºF. Therefore, 150 pounds is attributed for loss of preload during the life of the component, associated with a neutron fluence exposure of 3.02E+18 n/cm^2. The analysis for loss of preload due to neutron fluence has been identified as a TLAA for the jet pump slip joint clamps that requires evaluation for the subsequent period of extended operation.

TLAA Evaluation:

In order to evaluate the clamp loss of preload TLAA, the projected fluence at clamp locations inside the reactor vessel was determined from initial clamp installation (Unit 1 at the start of cycle 13, Unit 2 at the start of cycle 14) through the end of the subsequent period of extended operation. RAMA fluence projections were performed that specifically modeled the limiting location of the clamps installed (“oldest” clamps). The peak fluence value is projected to reach 4.98E+18 n/cm^2 (Unit 1) and 6.83E+18 n/cm^2 (Unit 2) at the end of the subsequent period of extended operation. Since these values are more than the design value of 3.02E+18 n/cm^2, this TLAA must be evaluated further to determine if the loss of preload is acceptable.

An evaluation was performed to determine the preload loss in the jet pump slip joint repair clamps. The maximum calculated relaxation (in % loss compared to original specification) is 12 for Unit 1 and 16 for Unit 2. This does not diminish the preload past the end-of-life requirement of 350 lbs. Therefore, the acceptability is assured during the subsequent period of extended operation.

TLAA Disposition:

10 CFR 54.21(c)(1)(ii): The jet pump slip joint repair clamp analysis for loss of preload has been projected to the end of the subsequent period of extended operation.

4.2.11 Jet Pump Auxiliary Spring Wedge Assembly Loss of Preload Analysis

TLAA Description:

The BFN jet pump assemblies have had auxiliary spring wedge assemblies installed to maintain lateral support for the jet pump inlet mixer. The design stress analysis considered potential aging effects, including loss of preload due to radiation effects based upon a design life of 40 years. The auxiliary spring wedge assemblies were installed in Units 1, 2, and 3 on varying jet pumps.

The oldest auxiliary spring wedge assemblies were installed during refuel outage 6 for Unit 1, refuel outage 13 for Unit 2, and refuel outage 12 for Unit 3.

The stress analysis indicated that fluence of 1.81E+20 n/cm^2 was considered for the auxiliary spring wedge assembly 40-year design life. The analysis for loss of preload due to neutron fluence has been identified as a TLAA for the auxiliary spring wedge assemblies, that requires evaluation for the subsequent period of extended operation.

TLAA Evaluation:

To evaluate loss of preload for the subsequent period of extended operation, RAMA fluence projections were developed for the bounding auxiliary spring wedge assembly locations in each unit. The maximum value determined from the RAMA fluence analysis was 1.52E+20 n/cm^2 for Unit 1 and 1.55E+20 n/cm2 for Units 2 and 3. This is less than the original design analysis considered. Therefore, the design stress analysis remains valid through the subsequent period of extended operation.

TLAA Disposition:

10 CFR 54.21(c)(1)(i) - The jet pump auxiliary spring wedge assembly design stress analysis for loss of preload remains valid through the subsequent period of extended operation.

4.2.12 Jet Pump Riser Repair Clamp Loss of Preload Analysis

TLAA Description:

During in-vessel inspections, crack indications were identified at the two attachment welds of the riser brace to the riser pipe adjacent to jet pump (JP) 5 at reactor vessel 90° azimuth on BFN Unit 3. A mechanical clamping system designed to structurally replace these welds was installed on both jet pump risers in 1995 prior the restart of Unit 3. Since these clamps use bolts to maintain the proper clamping force, loss of preload due to neutron irradiation stress relaxation was a design consideration. The stress analysis of the clamp analyzed preload losses based on neutron fluence of 1.89E+20 n/cm^2 for the clamp bolt and 3.15E+20 n/cm^2 for the support bolt. Since the neutron fluence values were assumed through the end of the initial 40 years of operation, the design analysis has been identified as a TLAA that requires evaluation for the subsequent period of extended operation.

TLAA Evaluation:

In order to determine if this fluence assumption will remain valid through 80 years of operation, the neutron fluence was projected to 62 EFPY using the RAMA fluence methodology previously described in Section 4.2.1.2. The 62 EFPY fluence value for the Unit 3 jet pump riser clamp location was determined to be 1.38E+20 n/cm^2. This is less than both the originally analyzed fluence values for the clamp and support bolts.

Therefore, the riser clamp design analysis for loss of preload is valid through the subsequent period of extended operation.

TLAA Disposition:

10 CFR 54.21(c)(1)(i) - The analysis for jet pump riser repair clamp loss of preload remains valid through the subsequent period of extended operation.

4.2.13 Replacement Core Support Plate Plug Extended Life Irradiation - Enhanced Stress Relaxation Analysis

TLAA Description:

The original design of the BFN core support plates included holes for bypass flow. It was discovered that the flow through the holes produced high velocity jets that impinged on the in-core instrument tubes which subjected them to high levels of flow induced vibration which led to wear on the adjacent fuel channels. The plug mandrel spring holds the extended life core support plate plug, tight in the core support plate, against a force created by the differential pressure across the core support plate. BFN Units 2, and 3 have had all the original core support plate plugs replaced. BFN Unit 1 has had only a small population of core support plate plugs replaced. The original core support plate plugs had a service life of approximately 14 years. BFN will replace the original core support plate plugs during the outage which corresponds to the end of their service life. The extended life core support plate plugs have a service life of 35 EFPY corresponding to a fluence of 5.25E+20 n/cm^2. Due to the effects of irradiation-enhanced stress relaxation, the amount of force applied by the plug mandrel spring is dependent on the accumulated neutron fluence. Irradiation-enhanced stress relaxation of the mandrel spring due to neutron irradiation has been identified as a TLAA and must be evaluated for the subsequent period of extended operation.

TLAA Evaluation:

An analysis was prepared to evaluate the acceptability of the core support plate plug preload loss during the subsequent period of extended operation. The analysis determined that the core support plate plugs were initially designed to maintain sufficient preload when subjected to a fluence value **{{ }}**. The fluence values calculated during the reactor vessel internals fast neutron fluence analyses for the subsequent period of extended operation are shown in Table 4.2.13-1.

Table 4.2.13-1, BFN Core Support Plate Plug Fast Neutron Fluence (n/cm^2)

Unit 1	Unit 2	Unit 3
50 EFPY	**64 EFPY**	**62 EFPY**
7.28E+20	7.13E+20	7.63E+20

The analysis concluded that since the calculated fluence values for 50, 64, and 62 EFPY, for Units 1, 2, and 3, respectively, are less than the design fluence value, the extended life of the core support plate plugs has no adverse impact on the acceptability of the component's operation during the subsequent period of extended operation.

TLAA Disposition:

10 CFR 54.21(c)(1)(ii) - The analysis for the core support plate plug irradiation-enhanced stress relaxation has been projected through the subsequent period of extended operation.

4.2.14 Irradiation Assisted Stress Corrosion Cracking (IASCC) of Reactor Vessel Internals

TLAA Description:

Section 4.7.6 of the BFN LRA presents a fluence threshold value of 5.0E+20 n/cm^2 beyond which IASCC and embrittlement may occur in BWR vessel internal components. Section 4.7.6 of the BFN LRA concludes that the expected fluence on the core shroud, top guide, core plate, and in-core instrumentation dry tubes and guide tubes exceed the threshold of 5.0E+20 n/cm^2 at the end of the 60- year first period of extended operation. Aging management was required for these components through the first period of extended operation. Since the analysis presented in Section 4.7.6 of the BFN LRA determined that IASCC and embrittlement were aging effects expected to occur in 60-years, this analysis has been identified as a TLAA that requires evaluation for the subsequent period of extended operation.

TLAA Evaluation:

Fluence projections for BFN Units 1, 2, and 3 core shroud, top guide, core plate, and in-core instrumentation dry tubes exceed the screening criteria of 5.0E+20 n/cm^2 at the end of the subsequent period of extended operation. Therefore, these components will be inspected periodically for cracking and loss of fracture toughness (embrittlement) during the subsequent period of extended operation in accordance with the BWR Vessel Internals aging management program.

For periodic core shroud inspections, the BWR Vessel Internals aging management program utilizes the recommendations provided in BWRVIP-76-R1-A, “BWR Vessel and Internals Project, BWR Core Shroud Inspection and Flaw Evaluation Guidelines.” For periodic top guide inspections, the BWR Vessel Internals Aging Management Program utilizes the recommendations provided in BWRVIP-26-A, “BWR Vessel and Internals Project, BWR Top Guide Inspection and Flaw Evaluation Guidelines,” and BWRVIP-183, “BWR Vessel and Internals Project, Top Guide Grid Beam Inspection and Flaw Evaluation Guidelines.” For periodic core plate inspections, the BWR Vessel Internals Aging Management Program utilizes the recommendations provided in BWRVIP-25-R1-A, “BWR Vessel and Internals Project, BWR Core Plate Inspection and Flaw Evaluation Guidelines.” For periodic in-core instrumentation dry tube inspections, the BWR Vessel Internals Aging Management Program utilizes the recommendations provided in BWRVIP-47-A, “BWR Vessel and Internals Project, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines.”

Therefore, aging effects of IASCC and embrittlement on the core shroud, top guide, core plate, and the in-core instrumentation dry tubes will be managed in the subsequent period of extended operation in accordance with the BWR Vessel Internals program (B.2.1.7).

TLAA Disposition:

10 CFR 54.21(c)(1)(iii) - Aging effects of IASCC and embrittlement on the core shroud, top guide, core plate, and the in-core instrumentation dry tubes will be managed by the BWR Vessel Internals program (B.2.1.7) through the subsequent period of extended operation.

4.2.15 Core Spray Replacement Piping Bolting Loss of Preload Evaluation

TLAA Description:

Intergranular stress corrosion cracking indications were observed on BFN Unit 3 piping during in-vessel inspection. A sectional replacement of the lower core spray sparger line was installed on BFN Unit 3. The repair is a bolted replacement of the lower section of the core spray piping in the downcomer region. The sectional replacement was only installed at 7.5°.

The design specification for this repair component states that the fast neutron flux (E > 1.0 MeV) at the repair locations is less than 4.8E+10 n/cm^{2}s, and that it will not affect the properties of the lower sectional replacement materials for the design life of 40 years. Calculating a conservative fluence value (assume 100% capacity factor) from this flux using a 40-year design life equates to 6.05E+19 n/cm^2.

Since the design report evaluated the effects of fluence on loss of preload over a 40-year service life, the evaluation has been identified as a TLAA that requires evaluation for the subsequent period of extended operation.

TLAA Evaluation:

In order to determine if this fluence assumption will remain valid through 80 years of operation, the neutron fluence was projected to 62 EFPY using the RAMA fluence methodology previously described in Section 4.2.1.2. The 62 EFPY fluence value for the Unit 3 core spray piping bolting piping location was determined to be 4.82E+17 n/cm^2. This is less than the originally analyzed value of 6.05E+19 n/cm^2.

Therefore, the core spray replacement piping bolting analysis for loss of preload is valid through the subsequent period of extended operation.

TLAA Disposition:

10 CFR 54.21(c)(1)(i) - The Unit 3 replacement core spray piping bolting loss of preload evaluation remains valid through the subsequent period of extended operation.

4.2.16 Core Spray Sparger Repair Clamp Loss of Preload Evaluation

TLAA Description:

A repair clamp device was installed during the Unit 1 restart effort due to cracking found in the heat affected zone of the core spray sparger T-box. The clamp assembly will be subject to high neutron irradiation and the fasteners which were preloaded during installation will be relaxed.

Per review of the design analysis, it is specified that the relaxation of the bolt preload due to fast neutron fluence of 1.4E+19 n/cm^2 for a 40-year design life is considered in the evaluation.

Since the design report evaluated the effects of fluence on loss of preload over a 40-year service life, the evaluation has been identified as a TLAA that requires evaluation for the subsequent period of extended operation.

TLAA Evaluation:

In order to determine if this fluence assumption will remain valid through 80 years of operation, the neutron fluence was projected to 50 EFPY using the RAMA fluence methodology previously described in Section 4.2.1.2. The 50 EFPY fluence value for the Unit 1 core spray sparger repair clamp location was determined to be 2.94E+19 n/cm^2. This is greater than the originally analyzed value of 1.4E+19 n/cm^2. An additional analysis was prepared to evaluate the repair clamps acceptability for the subsequent period of extended operation. The analysis found that it is acceptable to compare the calculated fluence to the stress relaxation screening criteria of 1.3E+20 n/cm^2 in BWRVIP-315.

Therefore, the core spray repair clamp analysis for loss of preload has been projected through the subsequent period of extended operation.

TLAA Disposition:

10 CFR 54.21(c)(1)(ii) - The Unit 1 core spray repair clamp analysis for loss of preload has been projected through the subsequent period of extended operation.

4.2.17 Access Hole Cover Repair Loss of Preload Evaluation

TLAA Description:

Due to cracking at the welded connection between the shroud baffle plate and access hole cover, the original supplied access hole covers were replaced with a bolted design during the BFN Unit 1 restart effort. This repair was also installed in 2023 for Unit 2. The same repair is scheduled to be installed in Unit 3 in year 2024.

The fasteners of the replacement access hole covers are preloaded when installed. Per review of the design reports a preload relaxation of 20% is considered over a 40-year design life. Since the design report evaluated the effects of fluence on loss of preload over the design life, the evaluation has been identified as a TLAA that requires evaluation for the subsequent period of extended operation.

TLAA Evaluation:

An evaluation was prepared to determine the irradiation induced preload loss in the access hole cover repair bolts. The analysis found that due to the low accumulated fluence in the access hole area, the expected preload loss was less than 1%. Therefore, the analysis remains valid for the subsequent period of extended operation.

TLAA Disposition:

10 CFR 54.21(c)(1)(i) - The analysis of the access hole cover repair loss of preload remains valid through the subsequent period of extended operation.

4.2.18 Jet Pump Hold-Down Beam Assembly Loss of Preload Analysis

TLAA Description:

All BFN jet pump assemblies have had jet pump hold-down beam assemblies installed. The original hold down beam assemblies have been replaced with Group 2 beam bolt assemblies. On

Unit 3, the JP 19 and JP 20 beam bolt assemblies were replaced with Group 3 beam bolt assemblies. The Group 2 and Group 3 beam bolt assemblies are constructed of X-750 alloy. The axial compressive bolt is preloaded, and over time this preload is relaxed due to the thermal environment and neutron irradiation of the component.

Since the component is subject to a loss of preload within the design life, the evaluation has been identified as a TLAA that requires evaluation for the subsequent period of extended operation.

TLAA Evaluation:

An evaluation was prepared to determine if the calculated preload loss in the beam bolt was acceptable for the subsequent period of extended operation. The analysis found that the jet pump beam assembly can maintain functionality up to a fluence level of approximately 7.17E+20 n/cm^2 (E > 1 MeV) for Group 2 beam bolt assemblies and 6.12E+20 n/cm^2 (E > 1 MeV) for Group 3 beam bolt assemblies. The peak fast neutron fluence for the BFN jet pump beam assemblies is projected to be 1.57E+20 n/cm^2 (E > 1 MeV). Therefore, the BFN jet pump hold-down beam assembly loss of preload analysis is acceptable and has been projected to the end of the subsequent period of extended operation.

TLAA Disposition:

10 CFR 54.21(c)(1)(ii) - The jet pump hold-down beam assembly loss of preload analysis has been projected to the end of the subsequent period of extended operation.

4.2.19 Jet Pump Sensing Line Clamps Loss of Preload Analysis

TLAA Description:

Jet pump sensing line clamps were installed on BFN Units 1, 2, and 3 to mitigate increased vibration excitation associated with uprated power conditions. The modification consists of a C-clamp assembly which clamps tightly to both the diffuser and the sensing line. Over the design life of the clamp, the bolt preload will be reduced due to thermal and irradiation induced relaxation.

Since the component is subject to a loss of preload within the design life, the evaluation has been identified as a TLAA that requires evaluation for the subsequent period of extended operation.

TLAA Evaluation:

An evaluation was prepared to determine if the calculated preload loss in the sensing line clamp was acceptable for the subsequent period of extended operation. The original design of the sensing line clamp assumed a fluence value of 1.0E+19 n/cm^2 corresponding to a preload relaxation of 5% for the 40-year design life. The evaluation found that the maximum fluence of 4.43E+18 n/cm^2 calculated is less than the design analyzed value of 1.0E+19 n/cm^2.

Therefore, the jet pump sensing line clamp loss of preload analysis remains valid through the end of the subsequent period of extended operation.

TLAA Disposition:

10 CFR 54.21(c)(1)(i) - The jet pump sensing line clamp loss of preload analysis remains valid through the subsequent period of extended operation.

4.3 METAL FATIGUE ANALYSES

Fatigue analyses are required on components designed to ASME, Section III, Class 1 and Class MC. In addition, certain other codes such as ASME Section III, Class 2 and 3, USA Standard (USAS) American National Standard Institute (ANSI) B31.1, and ASME 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 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 BFN Units 1, 2, and 3. Each of the potential TLAAs were evaluated against the six TLAA screening criteria specified in 10 CFR 54.3. Those that were identified as BFN fatigue TLAAs are evaluated using 80-year transient cycle and cumulative usage projections, described is Section 4.3.1, and summarized in the following subsections:

- ASME Section III, Class 1 Fatigue Analyses (Section 4.3.2)
- ASME Section III, Class 1 Fatigue Waivers (Section 4.3.3)
- ASME Section III, Class 2 and 3 and ANSI B31.1 Allowable Stress Analyses (Section 4.3.4)
- Environmental Fatigue Analyses for RPV and Class 1 Piping (Section 4.3.5)
- Replacement Steam Dryer Stress Report and Fatigue Evaluation (Section 4.3.6)
- Emergency Equipment Cooling Water Weld Flaw Evaluation (Section 4.3.7)
- Core Shroud Support Fatigue Analysis Reevaluation (Section 4.3.8)
- BFN Unit 3 Core Spray T-Box Repair Fatigue Evaluation (Section 4.3.9)
- BFN Unit 3 Core Spray Lower Line Section Replacement Fatigue Evaluation (Section 4.3.10)
- Jet Pump to Core Shroud Support Plate Fatigue Evaluation (Section 4.3.11)

4.3.1 Transient Cycle and Cumulative Usage Projections for 80 Years

Fatigue analyses are based upon explicit numbers and amplitudes of thermal and pressure transients usually described in design specifications. The intent of the design basis transient definitions is to bound a wide range of possible events with varying ranges of severity in temperature and pressure. The existing fatigue analyses are based upon the number of transient cycles postulated to bound 60 years of service.

Projections of the transient cycles through the subsequent period of extended operation were developed to determine whether the existing analyses remain valid for 80 years. These transient cycles and projections are documented in Table 4.3.1-1, Table 4.3.1-2, and Table 4.3.1-3 for BFN Units 1, 2 and 3, respectively.

Analyses supporting Subsequent License Renewal were originally performed with 2018 transient cycle data but were updated with 2022 data. The following evaluations were identified as still being bounded by 2018 transient data: RPV Closure Stud Bolts (Table 4.3.1-4), Section 4.3.9, Section 4.3.10, and Section 4.7.3

The cycle projection rates are based on FatiguePro™ 3 projection methodology. Since most nuclear power plants, including BFN Units 1, 2 and 3, have experienced a significant declining trend in accumulation of transients over time, transient projections based on recent operating experience provides an accurate basis for future projections. The FatiguePro™ 3 projection methodology provides for incorporation of a short- and long-term weighting factor. This is coupled with historical data for each of the transients which is used to develop the 80-year projection values.

For transient numbers 2, 9, 11, 16, 20, 21, 24, 31, 32, which have never occurred, the projected number of transient cycles was assumed to be 1 (one) over 80 years.

The first column of each table provides the transients numbers. The second column of each table provides the transient description, and the third column of each table lists the cumulative numbers of transient cycles as of December 31, 2022.

These counts include transient cycles during pre-operational startup. The fourth column in Table 4.3.1-1, Table 4.3.1-2, and Table 4.3.1-3 shows the numbers of transient cycles projected to occur over 80 years. The fifth column in both Table 4.3.1-1, Table 4.3.1-2, and Table 4.3.1-3 lists the design transient cycles, which are the assumed numbers of transient cycles analyzed in the most recent fatigue analyses for components requiring Cumulative Usage Factor (CUF) analyses in accordance with ASME Section III. Several of the 80-year transient cycle projections in the fourth column of each table exceed the assumed number of original design transient cycles in the fifth column. However, the assumed number of design transient cycles does not represent a final design limit; rather, the design limit is that the CUF or Environmentally Adjusted Cumulative Usage Factor (CUF_{en}) does not exceed a value of 1.0. Since the CUF or CUF_{en} of a component is computed as a function of multiple thermal and pressure transients, increasing the number of transient cycles for one transient type to a value greater than the number assumed in the fatigue analysis may not cause the CUF or CUF_{en} to exceed the design limit. The 80-year projected transient cycle numbers shown in the fourth column of each table were used as input to calculate the projected 80-year CUF and CUF_{en} values shown in Table 4.3.1-4. All projected 80-year CUF and CUF_{en} values in Table 4.3.1-4 meet the appropriate acceptance criteria (e.g., CUF limit of 1.0 for ASME Section III locations and CUF_{en} limit of 1.0).

The 80 year projection for Table 4.3.1-4 Location 24, Support Skirt, was calculated by projecting the 60-year CUF value by a factor of 1.33.

Consistent with Section X.M1 of the GALL-SLR Report, the Fatigue Monitoring program (B.3.1.1) monitors applicable plant transients that cause cyclic strains and contribute to fatigue, as specified in the underlying component fatigue analyses, and monitors or validates appropriate environmental parameters that contribute to environmental fatigue multiplier (F_{en}) values. The number of occurrences and the severity of the plant transients that contribute to the fatigue analyses for each component are monitored. FatiguePro™ is used at BFN to determine the overall effect of the cumulative numbers of transient cycles that have occurred at a given time and determines the CUF values for all monitored locations resulting from the combination of transient cycles that have occurred during the period.

The initial BFN LRA committed to enhancing the Fatigue Monitoring program to include automated transient cycle counting and automated calculation and tracking of fatigue CUFs. As a result, the BFN FatiguePro™ software was implemented in 2013.

FatiguePro™ is a computerized data acquisition, recording, and thermal transient and cumulative fatigue usage tracking program.

The BFN FatiguePro^{TM} automated transient cycle counting module uses temperature and pressure parameters, including the rates of changes of these parameters, to properly count and categorize transient cycles and calculate CUFs for critical plant components. The transient cycles assigned by FatiguePro^{TM} are periodically reviewed to ensure all transient cycles are correctly captured and assigned. This review also ensures that the cyclic load severities used in the fatigue parameter calculations remain bounding.

The BFN FatiguePro^{TM} software includes the calculation and tracking of Environmentally Assisted Fatigue (EAF) in accordance with NUREG/CR-6909 Revision 0 (Reference 4.8.48) at the locations identified in NUREG/CR-6260 (Reference 4.8.49) for the older-vintage General Electric plant, as well as other limiting plant-specific locations. For these locations, CUF_{en} is calculated and tracked by the program. Actual plant water chemistry conditions are periodically reviewed and compared to the conditions assumed in the EAF calculations to confirm that the water chemistry parameters used to calculate the Environmentally Assisted Fatigue Correction Factor (F_{en}) values remain valid.

The CUF and CUF_{en} values for the components monitored by FatiguePro^{TM} are compared to appropriate acceptance criterion (e.g., 1.0 for ASME Section III locations or 1.0 for CUF_{en}). If the CUF values do not exceed the allowable values, the design limits remain satisfied. If monitored incremental CUF or CUF_{en} values exceed 70 percent of the applicable limit, then the condition will be entered into the corrective action program and evaluated for corrective action to be taken prior to exceeding the applicable final design limit acceptance criterion.

Eighty-year projections of CUF and CUF_{en} for the limiting locations monitored at BFN Units 1, 2, and 3 are shown on Table 4.3.1-4. Monitoring of the limiting locations using FatiguePro^{TM} maintains assurance that all Class 1 locations remain bounded and design limits for fatigue and EAF remain satisfied throughout subsequent period of extended operation and allow for sufficient time to initiate actions when design limits are approached.

Since the methodology that calculated the 80-year CUF and CUF_{en} projections assumed the larger number transient cycle projections from either Unit 1 in Table 4.3.1-1, Unit 2 in Table 4.3.1-2, or Unit 3 in Table 4.3.1-3, the projected 80-year CUF and CUF_{en} values in Table 4.3.1-4 are bounding to Units 1, 2 and 3.

The last column in Table 4.3.1-1, Table 4.3.1-2, and Table 4.3.1-3 document applicable BFN FSAR sections. For transients in Table 4.3.1-1, Table 4.3.1-2, and Table 4.3.1-3 which do not have a specified FSAR section, the BFN corrective action program is being used to initiate inclusion of those transients in the FSAR.

The 80-year transient cycle projections provided in Table 4.3.1-1, Table 4.3.1-2, and Table 4.3.1-3 and the resulting 80-year CUF and CUF_{en} projections provided in Table 4.3.1-4, were used to evaluate the fatigue TLAAs in Sections 4.3.2 through 4.3.8. The FatiguePro^{TM} software will monitor the transients provided in Table 4.3.1-1, Table 4.3.1-2, and Table 4.3.1-3 in the subsequent period of extended operation. Prior to entry into the subsequent period of extended operation, the BFN Fatigue Monitoring program will transition to FatiguePro^{TM} Version 4 (from Version 3).

Table 4.3.1-1, BFN Unit 1 - 80-Year Transient Cycle Projections

Transient Number (Note 1)	Transient Description	Cumulative Transient Cycles to-date (12/31/22)	80-Year Projected Transient Cycles	No. of Design Transient Cycles	FSAR Section
1	Boltup	24	43	123	Section 4.2.5
2	Design Basis Accident	0	1	---	(Note 5)
3	Design Hydrostatic Test to 1,250 psig (Note 6)	28	50	130	Section 4.2.5
4	Daily Reduction to 75% Power and Rod Pattern Change	352	619	10,000	Section 4.2.5
5	HPCI Injection (ΔT = 250°F)	80	80	---	(Note 5)
6	HPCI Injection (ΔT = 350°F)	192	192	---	(Note 5)
7	HPCI Injection (ΔT = 450°F)	221	221	---	(Note 5)
8	Hydrostatic Test to 1,563 psig	1	1 (Note 2)	3	Section 4.2.5
9	Improper Start of Cold Recirculation Loop	0	1	5	Section 4.2.5
10	Loss of Feedwater Heaters - Partial Feedwater Heater Bypass	130	155 (Note 4)	70	Section 4.2.5
11	Loss of Feedwater Heaters - Turbine Trip at 25% Power	0	1	---	(Note 5)
12	SCRAM - Loss of Feedwater Pumps, Isolation Valves Close	3	7	10	Section 4.2.5
13	Loss of Reactor Water Cleanup	30	99	---	(Note 5)
14	Minor Cooldown	50	50	---	(Note 5)
15	Minor Heatup	50	50	---	(Note 5)
16	Operating Basis Earthquake	0	1	---	(Note 5)
17	RCIC Injection (ΔT = 250°F)	80	80 (Note 3)	---	(Note 5)
18	RCIC Injection (ΔT = 350°F)	188	188	---	(Note 5)
19	RCIC Injection (ΔT = 450°F)	226	239	---	(Note 5)
20	SCRAM - Reactor Overpressure with Delayed Scram, Feedwater Stays On, Isolation Valves Stay Open	0	1	1	Section 4.2.5
21	Small Break Accident	0	1	---	(Note 5)
22	SCRAM - Other SCRAMS	52	59	147	Section 4.2.5

Table 4.3.1-1, BFN Unit 1 - 80-Year Transient Cycle Projections (Continued)

Transient Number (Note 1)	Transient Description	Cumulative Transient Cycles to-date (12/31/22)	80-Year Projected Transient Cycles	No. of Design Transient Cycles	FSAR Section
23	SCRAM - Turbine Generator Trip, Feedwater Stays On, Isolation Valves Stay Open	51	55 (Note 4)	40	Section 4.2.5
24	Emergency Shutdown (Core Spray Injection)	0	1	---	(Note 5)
25	Shutdown - Hot Standby (Feedwater Injection ΔT = 250°F)	80	84	---	(Note 5)
26	Shutdown - Hot Standby (Feedwater Injection ΔT = 350°F)	189	193	---	(Note 5)
27	Shutdown - Hot Standby (Feedwater Injection ΔT = 450°F)	219	223	---	(Note 5)
28	Shutdown - Reduction to 0% Power	178	182	---	(Note 5)
29	Shutdown - Vessel Flooding	134	134	---	(Note 5)
30	Shutdown / Major Cooldown	144	187 (Note 4)	118	Section 4.2.5
31	Standby Liquid Control Operation	0	1	10	Section 4.2.5
32	SCRAM - Single Relief or Safety Valve Blowdown	0	1	2	Section 4.2.5
33	Safety Relief Valve Actuations	190	190	---	(Note 5)
34	Startup/Major Heatup	150	191 (Note 4)	120	Section 4.2.5
35	Sudden Start of Pump in Cold Recirculation Loop	1	1	5	Section 4.2.5
36	Turbine Roll and Increase to Rated Power	196	246	---	(Note 5)
37	Unbolt	23	42	123	Section 4.2.5

Table 4.3.1-1, BFN Unit 1 - 80-Year Transient Cycle Projections (Continued)

Transient Number (Note 1)	Transient Description	Cumulative Transient Cycles to-date (12/31/22)	80-Year Projected Transient Cycles	No. of Design Transient Cycles	FSAR Section
38	Weekly Reduction to 50% Power	14	55	2000	Section 4.2.5

Notes:

1. One cycle is assumed at 80-years for DBA--Design Basis Accident, IMPROPRECSU--Improper Recirculation Pump Startup, LFWHTT--LFWH - Turbine Trip w/100% Bypass, OBE--Operating Basis Earthquake, PRSREV--Unacceptable Pressure Reversal (Unit 3 only), RPVOVPRS--SCRAM - RPV Overpressure, SBA--Small Break Accident, SDCSINJECT--Shutdown Core Spray Injection, SLCOP--Standby Liquid Control Operation, SRVBLDN--Single Relief/Safety Valve Blowdown, and SUDSTRT--Sudden Start of Cold Recirculation Loop as the projection was zero.
2. This test would have been performed during plant construction and is not expected to occur again.
3. Although no additional cycles of RCIC250--RCIC Injection ΔT=250°F are projected to occur, cycles of the more severe ΔT=350°F and ΔT=450°F are expected to occur, so no margin is added to this projection.
4. Although the number of Cumulative Transient Cycles To-Date (12/31/22) in column 3 and the number of 80-Year Projected Transient Cycles in column 4, for transients 10, 23, 30, and 34 exceeds the “original” number of design transients in column 5 of this table, an analysis has been performed demonstrating that the resulting projected CUF and CUF_{en} values will continue to meet the acceptance criterion of 1.0.
5. Corrective action has been initiated to add these transient cycle descriptions to the BFN FSAR.
6. The Unacceptable Pressure Reversal During Hydrostatic Test transient is included in the Design Hydrostatic Test to 1,250 psig transient.

Table 4.3.1-2, BFN Unit 2 - 80-Year Transient Cycle Projections

Transient Number (Note 1)	Transient Description	Cumulative Transient Cycles to-date (12/31/22)	80-Year Projected Transient Cycles	No. of Design Transient Cycles	FSAR Section
1	Boltup	29	45	123	Section 4.2.5
2	Design Basis Accident	0	1	---	(Note 5)
3	Design Hydrostatic Test to 1,250 psig (Note 6)	36	55	130	Section 4.2.5
4	Daily Reduction to 75% Power and Rod Pattern Change	433	729	10,000	Section 4.2.5
5	HPCI Injection (ΔT = 250°F)	33	33	---	(Note 5)
6	HPCI Injection (ΔT = 350°F)	61	61	---	(Note 5)
7	HPCI Injection (ΔT = 450°F)	122	122	---	(Note 5)
8	Hydrostatic Test to 1,563 psig	1	1 (Note 2)	3	Section 4.2.5
9	Improper Start of Cold Recirculation Loop	0	1	5	Section 4.2.5
10	Loss of Feedwater Heaters - Partial Feedwater Heater Bypass	106	106 (Note 4)	70	Section 4.2.5
11	Loss of Feedwater Heaters - Turbine Trip at 25% Power	0	1	---	(Note 5)
12	SCRAM - Loss of Feedwater Pumps, Isolation Valves Close	6	6 (Note 4)	10	Section 4.2.5
13	Loss of Reactor Water Cleanup	18	56	---	(Note 5)
14	Minor Cooldown	73	73	---	(Note 5)
15	Minor Heatup	75	79	---	(Note 5)
16	Operating Basis Earthquake	0	1	---	(Note 5)
17	RCIC Injection (ΔT = 250°F)	34	34 (Note 3)	---	(Note 5)
18	RCIC Injection (ΔT = 350°F)	61	61	---	(Note 5)
19	RCIC Injection (ΔT = 450°F)	127	127	---	(Note 5)
20	SCRAM - Reactor Overpressure with Delayed Scram, Feedwater Stays On, Isolation Valves Stay Open	0	1	1	Section 4.2.5
21	Small Break Accident	0	1	---	(Note 5)
22	SCRAM - Other SCRAMS	75	79	147	Section 4.2.5

Table 4.3.1-2, BFN Unit 2 - 80-Year Transient Cycle Projections (Continued)

Transient Number (Note 1)	Transient Description	Cumulative Transient Cycles to-date (12/31/22)	80-Year Projected Transient Cycles	No. of Design Transient Cycles	FSAR Section
23	SCRAM - Turbine Generator Trip, Feedwater Stays On, Isolation Valves Stay Open	74	74 (Note 4)	40	Section 4.2.5
24	Emergency Shutdown (Core Spray Injection)	0	1	---	(Note 5)
25	Shutdown - Hot Standby (Feedwater Injection ΔT = 250°F)	34	34	---	(Note 5)
26	Shutdown - Hot Standby (Feedwater Injection ΔT = 350°F)	63	67	---	(Note 5)
27	Shutdown - Hot Standby (Feedwater Injection ΔT = 450°F)	122	126	---	(Note 5)
28	Shutdown - Reduction to 0% Power	206	213	---	(Note 5)
29	Shutdown - Vessel Flooding	124	124	---	(Note 5)
30	Shutdown / Major Cooldown	139	180 (Note 4)	118	Section 4.2.5
31	Standby Liquid Control Operation	0	1	10	Section 4.2.5
32	SCRAM - Single Relief or Safety Valve Blowdown	0	1	2	Section 4.2.5
33	Safety Relief Valve Actuations	318	318	---	(Note 5)
34	Startup/Major Heatup	141	182 (Note 4)	120	Section 4.2.5
35	Sudden Start of Pump in Cold Recirculation Loop	0	1	5	Section 4.2.5
36	Turbine Roll and Increase to Rated Power	214	246	---	(Note 5)
37	Unbolt	28	44	123	Section 4.2.5

Table 4.3.1-2, BFN Unit 2 - 80-Year Transient Cycle Projections (Continued)

Transient Number (Note 1)	Transient Description	Cumulative Transient Cycles to-date (12/31/22)	80-Year Projected Transient Cycles	No. of Design Transient Cycles	FSAR Section
38	Weekly Reduction to 50% Power	9	35	2000	Section 4.2.5

Notes:

1. One cycle is assumed at 80-years for DBA--Design Basis Accident, IMPROPRECSU--Improper Recirculation Pump Startup, LFWHTT--LFWH - Turbine Trip w/100% Bypass, OBE--Operating Basis Earthquake, PRSREV--Unacceptable Pressure Reversal (Unit 3 only), RPVOVPRS--SCRAM - RPV Overpressure, SBA--Small Break Accident, SDCSINJECT--Shutdown Core Spray Injection, SLCOP--Standby Liquid Control Operation, SRVBLDN--Single Relief/Safety Valve Blowdown, and SUDSTRT--Sudden Start of Cold Recirculation Loop as the projection was zero.
2. This test would have been performed during plant construction and is not expected to occur again.
3. Although no additional cycles of RCIC250--RCIC Injection ΔT=250 are projected to occur, cycles of the more severe ΔT=350 and ΔT=450 are expected to occur, so no margin is added to this projection.
4. Although the number of Cumulative Transient Cycles To-Date (12/31/22) in column 3 and the number of 80-Year Projected Transient Cycles in column 4, for transients 10, 23, 30, and 34 exceeds the “original” number of design transients in column 5 of this table, an analysis has been performed demonstrating that the resulting projected CUF and CUF_{en} values will continue to meet the acceptance criterion of 1.0.
5. Corrective action has been initiated to add these transient cycle descriptions to the BFN FSAR.
6. The Unacceptable Pressure Reversal During Hydrostatic Test transient is included in the Design Hydrostatic Test to 1,250 psig transient.

Table 4.3.1-3, BFN Unit 3 - 80-Year Transient Cycle Projections

Transient Number (Note 1)	Transient Description	Cumulative Transient Cycles to-date (12/31/22)	80-Year Projected Transient Cycles	No. of Design Transient Cycles	FSAR Section
1	Boltup	25	46	123	Section 4.2.5
2	Design Basis Accident	0	1	---	(Note 5)
3	Design Hydrostatic Test to 1,250 psig (Note 6)	23	44	130	Section 4.2.5
4	Daily Reduction to 75% Power and Rod Pattern Change	403	785	10,000	Section 4.2.5
5	HPCI Injection (ΔT = 250°F)	12	12	---	(Note 5)
6	HPCI Injection (ΔT = 350°F)	28	32	---	(Note 5)
7	HPCI Injection (ΔT = 450°F)	85	102	---	(Note 5)
8	Hydrostatic Test to 1,563 psig	1	1 (Note 2)	3	Section 4.2.5
9	Improper Start of Cold Recirculation Loop	0	1	5	Section 4.2.5
10	Loss of Feedwater Heaters - Partial Feedwater Heater Bypass	77	81 (Note 4)	70	Section 4.2.5
11	Loss of Feedwater Heaters - Turbine Trip at 25% Power	0	1	---	(Note 5)
12	SCRAM - Loss of Feedwater Pumps, Isolation Valves Close	4	4 (Note 4)	10	Section 4.2.5
13	Loss of Reactor Water Cleanup	30	114	---	(Note 5)
14	Minor Cooldown	42	49	---	(Note 5)
15	Minor Heatup	40	40	---	(Note 5)
16	Operating Basis Earthquake	0	1	---	(Note 5)
17	RCIC Injection (ΔT = 250°F)	12	12 (Note 3)	---	(Note 5)
18	RCIC Injection (ΔT = 350°F)	28	32	---	(Note 5)
19	RCIC Injection (ΔT = 450°F)	95	129	---	(Note 5)
20	SCRAM - Reactor Overpressure with Delayed Scram, Feedwater Stays On, Isolation Valves Stay Open	0	1	1	Section 4.2.5
21	Small Break Accident	0	1	---	(Note 5)
22	SCRAM - Other SCRAMS	40	40	147	Section 4.2.5

Table 4.3.1-3, BFN Unit 3 - 80-Year Transient Cycle Projections (Continued)

Transient Number (Note 1)	Transient Description	Cumulative Transient Cycles to-date (12/31/22)	80-Year Projected Transient Cycles	No. of Design Transient Cycles	FSAR Section
23	SCRAM - Turbine Generator Trip, Feedwater Stays On, Isolation Valves Stay Open	41	41 (Note 4)	40	Section 4.2.5
24	Emergency Shutdown (Core Spray Injection)	0	1	---	(Note 5)
25	Shutdown - Hot Standby (Feedwater Injection ΔT = 250°F)	12	12	---	(Note 5)
26	Shutdown - Hot Standby (Feedwater Injection ΔT = 350°F)	28	28	---	(Note 5)
27	Shutdown - Hot Standby (Feedwater Injection ΔT = 450°F)	79	79	---	(Note 5)
28	Shutdown - Reduction to 0% Power	155	155		(Note 5)
29	Shutdown - Vessel Flooding	115	115	---	(Note 5)
30	Shutdown / Major Cooldown	137	194 (Note 4)	118	Section 4.2.5
31	Standby Liquid Control Operation	0	1	10	Section 4.2.5
32	SCRAM - Single Relief or Safety Valve Blowdown	0	1	2	Section 4.2.5
33	Safety Relief Valve Actuations	239	239	---	(Note 5)
34	Startup/Major Heatup	140	204 (Note 4)	120	Section 4.2.5
35	Sudden Start of Pump in Cold Recirculation Loop	0	1	5	Section 4.2.5
36	Turbine Roll and Increase to Rated Power	174	235	---	(Note 5)
37	Unbolt	24	45	123	Section 4.2.5

Table 4.3.1-3, BFN Unit 3 - 80-Year Transient Cycle Projections (Continued)

Transient Number (Note 1)	Transient Description	Cumulative Transient Cycles to-date (12/31/22)	80-Year Projected Transient Cycles	No. of Design Transient Cycles	FSAR Section
38	Weekly Reduction to 50% Power	6	27	2000	Section 4.2.5

Notes:

1. One cycle is assumed at 80-years for DBA--Design Basis Accident, IMPROPRECSU--Improper Recirculation Pump Startup, LFWHTT--LFWH - Turbine Trip w/100% Bypass, OBE--Operating Basis Earthquake, PRSREV--Unacceptable Pressure Reversal (Unit 3 only), RPVOVPRS--SCRAM - RPV Overpressure, SBA--Small Break Accident, SDCSINJECT--Shutdown Core Spray Injection, SLCOP--Standby Liquid Control Operation, SRVBLDN--Single Relief/Safety Valve Blowdown, and SUDSTRT--Sudden Start of Cold Recirculation Loop as the projection was zero.
2. This test would have been performed during plant construction and is not expected to occur again.
3. Although no additional cycles of RCIC250--RCIC Injection ΔT=250 are projected to occur, cycles of the more severe ΔT=350 and ΔT=450 are expected to occur, so no margin is added to this projection.
4. Although the number of Cumulative Transient Cycles To-Date (12/31/22) in column 3 and the number of 80-Year Projected Transient Cycles in column 4, for transients 10, 23, 30, and 34 exceeds the “original” number of design transients in column 5 of this table, an analysis has been performed demonstrating that the resulting projected CUF and CUF_{en} values will continue to meet the acceptance criterion of 1.0.
5. Corrective action has been initiated to add these transient cycle descriptions to the BFN FSAR.
6. The Unacceptable Pressure Reversal During Hydrostatic Test transient is included in the Design Hydrostatic Test to 1,250 psig transient.

Table 4.3.1-4, BFN Units 1, 2, and 3 - Limiting Locations and 80-Year Projected CUF and CUF_{en} Values

No.	Location Description	Unit	80-Year CUF_{en}	80-Year CUF	Acceptance Criterion
1	Core Spray Nozzle Safe End (SS) (Note 1)	1, 2, 3	0.157	(Note 6)	1.0
2	Feedwater Piping Point 48, Riser Tee (CS) (Note 1)	1, 2, 3	0.848	(Note 6)	1.0
3	Feedwater Nozzle Location B/C (CS) (Note 2)	1	0.910	(Note 6)	1.0
4	Feedwater Piping Point 48, Riser Elbow (CS) (Note 2)	2, 3	0.614	(Note 6)	1.0
5	Recirculation Inlet Nozzle Blend Radius (LAS) (Note 2)	1, 2, 3	(Note 3)	(Note 6)	1.0
6	Recirculation Inlet Nozzle Safe End, Path 2 Inside (SS) (Note 4)	1, 2, 3	0.020	(Note 6)	1.0
7	Residual Heat Removal Return Point 269, Tee (SS) (Note 1)	2	0.201	(Note 6)	1.0
8	Residual Heat Removal Return Point 108C, Bend (SS) (Note 1)	1, 3	0.025	(Note 6)	1.0
9	Reactor Vessel Region A/ Feedwater Nozzle Location I (Blend Radius) (LAS) (Note 1)	1	0.934	(Note 6)	1.0
10	Reactor Vessel Region A / Feedwater Nozzle Location G/H (Blend Radius) (LAS) (Note 2)	1	0.914	(Note 6)	1.0
11	Reactor Vessel Region A / Feedwater Nozzle Location I (Blend Radius) (LAS) (Note 1)	2	0.745	(Note 6)	1.0
12	Reactor Vessel Region A / Feedwater Nozzle Location G/H (Blend Radius) (LAS) (Note 2)	2	0.720	(Note 6)	1.0
13	Reactor Vessel Region A / Feedwater Nozzle Location I (Blend Radius) (LAS) (Note 1)	3	0.596	(Note 6)	1.0
14	Reactor Vessel Region A / Feedwater Nozzle Location G/H (Blend Radius) (LAS) (Note 2)	3	0.572	(Note 6)	1.0
15	Reactor Vessel Region B / Recirculation Piping Point 148, RHR Suction Tee (SS) (Note 1)	2	0.555	(Note 6)	1.0
16	Reactor Vessel Region B / Recirculation Piping Point 148, RHR Suction Tee (SS) (Note 1) (Note 4)	1	0.115	(Note 6)	1.0
17	Reactor Vessel Region B / Recirculation Piping Point 148, RHR Suction Tee (SS) (Note 1) (Note 5)	3	0.105	(Note 6)	1.0

Table 4.3.1-4, BFN Units 1, 2, and 3 - Limiting Locations and 80-Year Projected CUF and CUF_{en} Values (Continued)

No.	Location Description	Unit	80-Year CUF_{en}	80-Year CUF	Acceptance Criterion
18	Reactor Vessel Region B / Recirculation Inlet Nozzle Blend Radius, Path 1 Inside (LAS) (Note 4)	1, 2, 3	0.255	(Note 6)	1.0
19	Reactor Vessel Region B / Core Spray Nozzle Blend Radius (LAS) (Note 1)	1, 2, 3	0.430	(Note 6)	1.0
20	Reactor Vessel Region B / Recirculation Outlet Nozzle Blend Radius (LAS) (Note 2)	1, 2, 3	0.199	(Note 6)	1.0
21	Reactor Vessel Region C / Shroud Support (LAS) (Note 2) (Note 7)	1, 2, 3	0.256	(Note 6)	1.0
22	Reactor Vessel Region C / Vessel Shell, Lower Head Area (LAS) (Note 1)	1, 2, 3	0.006	(Note 6)	1.0
23	CRD Penetration (NBA) (Note 8)	1, 2, 3	0.411	(Note 6)	1.0
24	Support Skirt	1, 2, 3	N/A	0.172	1.0
25	Refuel Containment Skirt	1, 2, 3	N/A	0.405	1.0
26	Main Closure Studs (Note 9) (Note 10)	1, 2, 3	0.726	(Note 6)	1.0

Notes:

1. NUREG/CR-6260 location.
2. Sentinel Location from Reference 4.8.58.
3. Results for the bounding Recirculation Inlet Nozzle Blend Radius location are shown in the RPV Region B zone.
4. Results for this location are from the Recirculation Inlet Nozzle reanalysis.
5. Results are for the Residual Heat Removal/Recirculation Point 59 and are bounding for Point 148.
6. The CUF value is not included in the table because it is bounded by the CUF_{en} value in column 4.
7. The fatigue within the shroud support bounds the fatigue for the shroud.
8. This location is included to support disposition of a BWRVIP Applicant Action Item (See Appendix C). This is not a bounding location and will not be monitored going forward.
9. These components are included in the Fatigue Monitoring Program for tracking of design basis fatigue usage factors during the subsequent period of extended operation.
10. The CUF_{en} value is bounding for all three units using the analysis based on 2018 transient cycle data.

4.3.2 Metal Fatigue of Class 1 Components

TLAA Description:

The BFN RPVs were originally designed for 40 years of service in accordance with the ASME Code Section III 1965 Edition, its interpretations, and applicable requirements, (including Summer 1965 Addenda for Units 1 and 2, and Summer 1966 Addenda for Unit 3) for Class 1 design requirements (Reference 4.8.56). All BFN piping systems were originally designed and evaluated in accordance with USAS (ANSI) B31.1 1967 design requirements, which did not include explicit fatigue analysis (Reference 4.8.56).

The RPV Class 1 fatigue analyses determined the effects of transient cyclic loadings resulting from changes in system temperature and pressure and for seismic loading cycles. The fatigue analyses evaluated explicit numbers and types of transients that were postulated for the 40-year design life of the plant in the design specifications. These Class 1 fatigue analyses were required to demonstrate that the CUF for each component will not exceed the design limit of 1.0 for all the postulated transients. The original, 40-year RPV fatigue analyses were evaluated for a 60-year service life and for EAF as part of the BFN initial LRA (Reference 4.8.28). The 60-year evaluations now serve as the CLB and have been identified as TLAAs for the subsequent period of extended operation.

These fatigue analyses have been identified as TLAAs that require evaluation for the subsequent period of extended operation.

TLAA Evaluation:

All BFN Class 1 fatigue analyses are based on the transient cycles listed in Table 4.3.1-1, Table 4.3.1-2, and Table 4.3.1-3. Table 4.3.1-4 documents the 80-year CUF and CUF_{en} projections for all plant-specific limiting locations based on the 80-year transient cycle projections in Table 4.3.1-1, Table 4.3.1-2, and Table 4.3.1-3. Table 4.3.1-4 demonstrates that the 80-year projected values of CUF and CUF_{en} for all locations remain less than the ASME Section III acceptance criterion through the subsequent period of extended operation.

To ensure the projected CUF and CUF_{en} values in Table 4.3.1-4 remain acceptable for the 80-year period of operation for Units 1, 2, and 3, the Fatigue Monitoring program (B.3.1.1) will monitor actual transient cycles and the associated CUF and CUF_{en} values for all limiting locations and ensure corrective actions are taken, if necessary, prior to exceeding the ASME Section III acceptance criterion.

The Fatigue Monitoring program will continue to use FatiguePro^{TM} to compute actual CUF and CUF_{en} values for all monitored locations. With this approach, the original numbers of design transient cycles are no longer a limit; instead, the ASME Section III acceptance criteria are the limits for each monitored location.

The Fatigue Monitoring program includes requirements that initiate corrective actions if any CUF or CUF_{en} values exceed 70 percent of the ASME Section III acceptance criteria. Corrective actions may include revision of the affected Class 1 fatigue analyses to address higher CUF or CUF_{en} values, establishing an inspection program using an approach acceptable to the NRC (such as inspections performed in accordance with Appendix L of ASME Code Section XI based on flow tolerance analysis), or repair or replacement of affected components prior to the CUF or CUF_{en} values exceeding their allowed values.

TLAA Disposition:

10 CFR 54.21(c)(1)(iii) - The effects of fatigue on the intended functions of components analyzed in accordance with ASME Section III, Class 1 requirements will be managed by the Fatigue Monitoring (B.3.1.1) program through the subsequent period of extended operation.

4.3.3 Class 1 Fatigue Waivers

TLAA Description:

The BFN reactor vessels were originally designed for 40 years of service in accordance with the ASME Code Section III 1965 Edition, its interpretations, and applicable requirements, (including Summer 1965 Addendum for the Units 1 and 2 reactor vessels and Summer 1996 Addendum for the Unit 3 reactor vessel) for Class 1 design requirements. The design stress reports for the Unit 1, Unit 2, and Unit 3 reactor vessels include fatigue waivers that determined that some reactor vessel components did not require explicit fatigue analyses because the criteria from ASME Section III, Paragraph N-415.1 were satisfied. The BFN reactor vessel components with fatigue waiver evaluations are listed in Table 4.3.3-1. Since the ASME Section III, Paragraph N-415.1 fatigue waiver criteria require postulated cycle input for the intended operating life of the plant, these fatigue waiver evaluations are TLAAs and have been re-evaluated for the subsequent period of extended operation using the 80-year projected number of transients in Tables 4.3.1-1, 4.3.1-2, and 4.3.1-3.

Table 4.3.3-1, Reactor Vessel Components Exempt Per ASME Section III, N-415.1

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TLAA Evaluation:

The original Class 1 fatigue waivers included assumptions for the total postulated number of temperature and pressure transients that were expected over the 40-year life of the plant. In addition, the original waivers evaluated significant load fluctuations expected over the 40-year life of the plant. Similar transients were combined into event groups and were assigned bounding temperature and pressure ranges. The event groups and applicable nozzles are shown in columns 1 and 2 of Table 4.3.3-2. Column 3 documents the specific transients, from Tables 4.3.1-1, 4.3.1-2, and 4.3.1-3, which make up each event group and column 4 documents the number of grouped events assumed in the original waivers.

The fatigue waivers were re-evaluated for the subsequent period of extended operation in accordance with the applicable ASME Section III, Paragraph N-415-1 criteria. The number of grouped events were increased in the reevaluation to bound or equal the summation of 80-year projections for the applicable transients listed in Table 4.3.1-1, 4.3.1-2, and 4.3.1-3. Pressure and temperature ranges for each event group were adjusted for EPU operating conditions. Table 4.3.3-2, column 5 shows the number of events assumed in the waiver reevaluation, column 6 shows the sum of the applicable 80-year projections from Table 4.3.1-1, column 7 shows the sum of the applicable 80-year projections from Table 4.3.1-2, and column 8 shows the sum of the applicable 80-year projections from Table 4.3.1-3.

The significant load fluctuations anticipated over the 80-year life of the plant were re-evaluated for each nozzle and/or component as part of the projected evaluation.

The results of the reevaluation showed that the criteria in ASME Section III, Paragraph N-415-1 remain satisfied for the subsequent period of extended operation.

TLAA Disposition:

10 CFR 54.21(c)(1)(ii) - The ASME Section III Class 1 fatigue waiver acceptance criterion continues to be satisfied based on 80-year projected transient cycles through the subsequent period of extended operation.

Table 4.3.3-2, Transient Summary for Fatigue Wavier Reevaluation

Event Grouping Assumed in the Original Waiver	Applicable Components	Applicable Transients, from Tables 4.3.1-1, 4.3.1-2 and 4.3.1-3, for Each Event Grouping Assumed in the Original Waiver	Number of Events Assumed in the Original Waiver	Number of Events Assumed in the Waiver Reevaluation	Number of 80-Year Projections for Event Grouping from Tables 4.3.1-1, 4.3.1-2, and 4.3.1-3, respectively		
					Unit 1	Unit 2	Unit 3
Atmospheric to Operating Conditions and Back Transients	All Nozzles and Jet Pump Replacement Penetration Seal	3) Hydrostatic Test (1250 psig) 34) Startup/Shutdown 12) SCRAM: Loss of FW pumps 8) Hydrotest (1563 psig)	263	266	245	244	253
Startup and Shutdown Transients	All Nozzles and Jet Pump Replacement Penetration Seal	34) Startup/Shutdown	120	204	191	182	204
Significant Temperature Fluctuation Transients	• Steam Outlet Nozzle • Instrumentation Nozzle • Vent Nozzle • Jet Pump Nozzle • Reactor Vessel Drain Nozzle • Jet Pump Replacement Penetration Seal	12) 2 X SCRAM: Loss of FW Pumps 20) SCRAM: Rx Overpressure 32) SCRAM: SRV Blowdown 14) and 15) Minor Heatup/Cooldown (Note 1)	23	93	58	93	59
	• Liquid Control Nozzle	31) Liquid Control System Operation 12) 2 X SCRAM: Loss of FW Pumps 20) SCRAM: Rx Overpressure 32) SCRAM: SRV Blowdown 14) and 15) Minor Heatup/Cooldown	33	94	59	94	60

Note 1: The event groupings that consider transients 14 and 15, only count the maximum number of cycles between Heatup and Cooldown, instead of counting both separately.

4.3.4 Metal Fatigue of Non-Class 1 Components

TLAA Description:

The BFN System Group II and III (ASME Section III, Class 2 and Class 3) safety-related piping, and other piping that is in scope for subsequent license renewal, was originally designed in accordance with the 1967 Edition of the USAS (ANSI) B31.1 Power Piping Code (ANSI B31.1). Piping systems designed in accordance with the ANSI B31.1 design rules are not required to have an explicit analysis of cumulative fatigue usage, but rather cyclic loading is considered in a simplified manner in the design process. ANSI B31.1 requires a stress range reduction factor be used based on the number of thermal and pressure cycles expected during the component operating lifetime. If the total number of fatigue cycles is expected to be 7000 or less, the stress range reduction factor of 1.0 is applied. For higher numbers of fatigue cycles, a stress range reduction factor of less than 1.0 is applied to the piping, which reduces the alternating stress range, reducing the likelihood of failure due to cyclic loading. The stress range reduction factors for piping designed to ANSI B31.1 requirements are shown in Table 4.3.4-1. The evaluation for required stress range reduction factors performed as part of piping design per ANSI B31.1 are implicit fatigue analyses since they are based upon 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.

Table 4.3.4-1, Stress Range Reduction Factors for Piping Designed per ANSI B31.1

Number of Equivalent Full Temperature Cycles	Stress Range Reduction Factor
7,000 and less	1.0
7,000 to 14,000	0.9
14,000 to 22,000	0.8
22,000 to 45,000	0.7
45,000 to 100,000	0.6
100,000 and over	0.5

TLAA Evaluation:

SLRA Tables 3.x.2-y (Refer to Section 3.0) identify piping, piping components, bolting, and valve bodies located within subsequent license renewal piping systems that were designed in accordance with ANSI B31.1. This includes components which are currently designated as ASME Section XI Class 1 components but were designed in accordance with ANSI B31.1. The identified piping components, bolting, and valve bodies are not associated with explicit cumulative fatigue usage analyses but rather support the piping system's implicit ANSI B31.1 fatigue analyses.

Portions of the following subsequent license renewal piping systems were designed in accordance with ANSI B31.1 requirements, but are attached to ASME Section III, Class 1 piping and are only affected by the same pressure and temperature transients as the Reactor Coolant System transients that are listed in Table 4.3.4-2: Control Rod Drive, Core Spray, Feedwater, Main Steam, Containment Atmosphere Dilution, Residual Heat Removal (RHR) (including Residual Heat Removal Service Water (RHRSW) since transients are bounded the RHR transients), and Standby Liquid Control. Only a subset of the transients listed in Table 4.3.4-2 apply to the Class 2, Class 3, and ANSI B31.1 piping within each system. Based on the data in

Table 4.3.4-2, the Feedwater Heater B nozzle is projected to be subject to the highest number of transient events over the course of 80 years of operation and is 3,332. Feedwater Heater B nozzle has the number of cycles because most of the transients in Table 4.3.4-2 affect it. Conservatively, 3,500 cycles will be used for the summation of all 80-year transient cycle projections from Table 4.3.4-2. Therefore, even if all operational Reactor Coolant System transients (i.e., transients 1 through 38) applied to each of these systems, the total number of projected 80-year cycles is less than 7000. Therefore, the stress range reduction factors originally applied for the components within these piping systems remain applicable and these implicit TLAAs remain valid through the subsequent period of extended operation.

Portions of the following systems were designed in accordance with ANSI B31.1 requirements and are affected by thermal and pressure transients that are different than the Reactor Coolant System transients that are listed in Table 4.3.4-2: Condensate/Demineralized Water, Emergency High Pressure Makeup, Auxiliary Boiler, High Pressure Fire Protection (Diesel-driven Pump), Carbon Dioxide, Off-Gas, Reactor Water Cleanup, Reactor Core Isolation Cooling (steam supply and turbine exhaust piping), High Pressure Coolant Injection (steam supply and turbine exhaust piping), Standby Diesel Generator, and Radiation Monitoring. Table 4.3.4-3 provides descriptions of the transient cycles that result in thermal or pressure cycles for these piping systems and the 80-year projected number of cycles through the subsequent period of extended operation. In all cases, the 80-year projected number of fatigue cycles is less than 7000. Therefore, the stress range reduction factors originally applied for the components within these piping systems remain applicable and these implicit TLAAs remain valid through the subsequent period of extended operation.

In addition, various high temperature sample lines were designed in accordance with ANSI B31.1 requirements. Table 4.3.4-4 provides descriptions of the transient cycles that result in thermal or pressure cycles for these sample lines and the 80-year projected number of cycles through the subsequent period of extended operation. In all cases the 80-year projected number of fatigue cycles is substantially less than 7000. Therefore, the stress range reduction factors originally applied for these sample lines remain applicable and these implicit TLAAs associated with these sample lines remain valid through the subsequent period of extended operation.

TLAA Disposition:

10 CFR 54.21(c)(1)(i) - All ASME Section III, Class 2, Class 3, and ANSI B31.1 allowable stress analyses remain valid through the subsequent period of extended operation.

Table 4.3.4-2, BFN - Transient Cycles

Transient Number	Transient Description	80-Year Projected Transient Cycles (Note 1)	No. of Design Transient Cycles	Affects Feedwater B Nozzle?
1	Boltup	46	123	No
2	Design Basis Accident	1	---	Yes
3	Design Hydrostatic Test to 1,250 psig (Note 3)	55	130	Yes
4	Daily Reduction to 75% Power and Rod Pattern Change	785	10,000	Yes
5	HPCI Injection (ΔT = 250°F)	80	---	No
6	HPCI Injection (ΔT = 350°F)	192	---	No
7	HPCI Injection (ΔT = 450°F)	221	---	No
8	Hydrostatic Test to 1,563 psig	1	3	Yes
9	Improper Start of Cold Recirculation Loop	1	5	Yes
10	Loss of Feedwater Heaters - Partial Feedwater Heater Bypass	155 (Note 2)	70	Yes
11	Loss of Feedwater Heaters - Turbine Trip at 25% Power	1	10	Yes
12	SCRAM - Loss of Feedwater Pumps, Isolation Valves Close	6 (Note 2)	10	Yes
13	Loss of Reactor Water Cleanup	114	---	Yes
14	Minor Cooldown	73	---	No
15	Minor Heatup	79	---	No
16	Operating Basis Earthquake	1	---	Yes
17	RCIC Injection (ΔT = 250°F)	80	---	Yes
18	RCIC Injection (ΔT = 350°F)	188	---	Yes
19	RCIC Injection (ΔT = 450°F)	239	---	Yes
20	SCRAM - Reactor Overpressure with Delayed Scram, Feedwater Stays On, Isolation Valves Stay Open	1	1	Yes
21	Small Break Accident	1	---	Yes
22	SCRAM - Other SCRAMS	79	147	Yes
23	SCRAM - Turbine Generator Trip, Feedwater Stays On, Isolation Valves Stay Open	74 (Note 2)	40	Yes
24	Emergency Shutdown (Core Spray Injection)	1	---	Yes
25	Shutdown - Hot Standby (Feedwater Injection ΔT = 250°F)	84	---	Yes

Table 4.3.4-2, BFN - Transient Cycles (Continued)

Transient Number	Transient Description	80-Year Projected Transient Cycles (Note 1)	No. of Design Transient Cycles	Affects Feedwater B Nozzle?
26	Shutdown - Hot Standby (Feedwater Injection ΔT = 350°F)	193	---	Yes
27	Shutdown - Hot Standby (Feedwater Injection ΔT = 450°F)	223	---	Yes
28	Shutdown - Reduction to 0% Power	213	---	Yes
29	Shutdown - Vessel Flooding	134	---	Yes
30	Shutdown / Major Cooldown	194 (Note 2)	118	Yes
31	Standby Liquid Control Operation	1	---	Yes
32	SCRAM - Single Relief or Safety Valve Blowdown	1	2	Yes
33	Safety Relief Valve Actuations	318	---	No
34	Startup/Major Heatup	204 (Note 2)	120	Yes
35	Sudden Start of Pump in Cold Recirculation Loop	1	5	Yes
36	Turbine Roll and Increase to Rated Power	246	---	Yes
37	Unbolt	45	123	No
38	Weekly Reduction to 50% Power	55	2000	Yes

Table 4.3.4-2 Notes:

1. BFN Unit 2 has the longest and most complete operational history of the three BFN units. However, for additional conservatism, the highest number of cycles for BFN Units 1, 2, and 3 for each transient is used.
2. FSAR Section 4.2.5 states that the specified number of cycles for a given transient may be exceeded over the life of the plant and that plant procedure has been implemented at Browns Ferry to maintain surveillance on the number of cycles which have occurred and the resulting fatigue usage factors. As stated in Note 4 to Table 4.3.1-1, Table 4.3.1-2, and Table 4.3.1-3, although the number of 80-Year Projected Transient Cycles in column 3, for transients 10, 23, 30, and 34 exceeds the “original” number of design transients in column 4 of this table, an analysis has been performed demonstrating that the resulting projected CUF and CUF_{en} values will continue to meet the acceptance criterion of 1.0.
3. The Unacceptable Pressure Reversal During Hydrostatic Test Transient is included in the Design Hydrostatic Test to 1,250 psig transient.

Table 4.3.4-3, 80-Year Transient Cycle Projections for Class 2, Class 3, and ANSI B31.1 Piping Systems Affected by Transients Other Than RCS Transients

Piping System	Description of Transient Cycles that Affects the Piping System	Conservative Assumptions Used in Projections	Projected Cycles for 80 Years
Main Steam	RPV Transients	3,500	3,500
Condensate/ Demineralized Water	Unit Startups	204	366
	Feedwater Trips / Loss of Feedwater Heating	162	
Feedwater	RPV Transients	3,500	3,500
Emergency High Pressure Makeup	Unit Startups	204	366
	Feedwater Trips / Loss of Feedwater Heating	162	
Auxiliary Boiler	Preoperational Testing	40	1,050
	Heating Season	850	
	RCIC Turbine Testing	120	
	HPCI Turbine Testing	40	
RHRSW	Bounded by RHR	3,500	3,500
High Pressure Fire Protection (Diesel-Driven Pump exhaust)	Preoperational Testing	100	1,540
	Diesel-driven Fire Protection pump (DDFP) Starts - Intended Function	80	
	DDFP - Surveillances	1,200	
	DDFP - Post Maintenance Testing	80	
	DDFP Starts - Other	80	
Carbon Dioxide	System Testing	1,020	1,100
	System Actuation - Intended Function	80	
Standby Liquid Control	RPV Transients	3,500	3,500
Off-Gas (Condenser Steam Packing Exhauster piping)	Normal Operation (sub-system operates continuously during plant operation)	296	296
Reactor Water Cleanup (RWCU)	RPV Transients	3,500	3,990
	RWCU Preoperational Testing	10	
	RWCU Pump Swap	160	
	RWCU Pump Maintenance	80	
	RWCU Heat Exchanger Swap	160	
	RWCU Heat Exchanger Maintenance	80	
RCIC (Steam Supply Piping)	RPV Transients	3,500	3,660
	Restoration of Steam Supply to RCIC Turbine after system maintenance	160	

Table 4.3.4-3, 80-Year Transient Cycle Projections for Class 2, Class 3, and ANSI B31.1 Piping Systems Affected by Transients Other Than RCS Transients (Continued)

Piping System	Description of Transient Cycles that Affects the Piping System	Conservative Assumptions Used in Projections	Projected Cycles for 80 Years
HPCI (Steam Supply Piping)	RPV Transients	3,500	3,660
	Restoration of Steam Supply to HPCI Turbine after system maintenance	160	
RCIC (Turbine Exhaust Piping)	Preoperational Testing	25	1,098
	RCIC Injections (Other than loss of Feedwater Pumps)	507	
	Scram Loss of Feedwater Pumps - Isolation Valves Close	6	
	RCIC Starts after Maintenance	160	
	RCIC Starts - Surveillances	400	
HPCI (Turbine Exhaust Piping)	Preoperational Testing	25	1,044
	HPCI Injections (Other than loss of Feedwater Pumps)	493	
	Scram Loss of Feedwater Pumps - Isolation Valves Close	6	
	HPCI Starts after Maintenance	160	
	HPCI Starts - Surveillances	360	
RHR	RPV Transients	3,500	3,500
Core Spray	RPV Transients	3,500	3,500
Standby Diesel Generator	Preoperational Testing	100	1,360
	Diesel Generator Starts - Intended Function	80	
	Diesel Generator - Surveillances	1,020	
	Diesel Generator - Post Maintenance Testing	80	
	Diesel Generator Starts - Other	80	
Containment Atmosphere Dilution	RPV Transients	3,500	3,500
Control Rod Drive	RPV Transients	3,500	3,500
Radiation Monitoring	Normal Operation (sub-systems operate continuously during plant operation)	296	296

Table 4.3.4-4, 80-Year Transient Cycle Projections for High Temperature Process Sample System Lines

Sample Line	Description of Transient Cycles that Affects the Sample Line	Conservative Assumptions Used in Projections	Projected Cycles for 80 Years
RHR Heat Exchanger Outlet Sample Lines	Manual sampling during plant shutdown to cold shutdown	294	454
	Transients resulting from system maintenance.	160	
Main Steam Sample Line	Manual sampling during plant operation	960	1,120
	Transients resulting from system maintenance	160	
Recirculation System sample line to Electrochemical Corrosion Potential/ Crack Growth Monitor	Sample line is in service continuously during reactor power operations	320	480
	Transients resulting from system maintenance	160	
RWCU Regenerative Heat Exchanger Outlet Sample Line	Manual sampling during plant operation	960	1,120
	Transients resulting from system maintenance	160	
Reactor Feedwater Sample Line	Sample line is in service continuously during reactor power operations	320	480
	Transients resulting from system maintenance	160	

4.3.5 Environmental Fatigue Analyses for Reactor Vessel and Class 1 Piping

TLAA Description:

NUREG-2191 Section X.M1, Fatigue Monitoring, provides guidance for evaluating the effects of the reactor water environment on the fatigue life of ASME Section III Class 1 components that contact the reactor coolant. One acceptable method for satisfying this guidance is to assess the impact of the reactor coolant environment on a sample set of critical components. These critical components should include those listed in NUREG/CR-6260 (Reference 4.8.49) for the plant type and vintage. Additional component locations should also be considered if they are more limiting than those listed in NUREG/CR-6260 for the plant.

FatiguePro^{TM} software was implemented and included the calculation and tracking of Environmentally Assisted Fatigue (EAF) cumulative usage factors (CUF_{en}) at the locations identified in NUREG/CR-6260 (Reference 4.8.49) for the older-vintage GEH plant. For these locations, the CUF_{en} values are calculated in accordance with NUREG/CR-6909, Revision 0 (Reference 4.8.48), NUREG/CR-6583 (Reference 4.8.50), and NUREG/CR-5704 (Reference 4.8.51) and are tracked by the Fatigue Monitoring program (B.3.1.1).

TLAA Evaluation:

For the SLR application environmental fatigue calculations were prepared in accordance NUREG/CR-6909, Revision 1 (Reference 4.8.48) for component location listed in NUREG/CR-6260 for the older-vintage BWR, which correlates to BFN. Also, for the SLR application, environmental fatigue screening calculations were performed for all RPV, piping, and other component locations that have an identified CUF value in a BFN CLB stress report or evaluation and are in contact with reactor water.

Consistent with NUREG-2191, Section X.M1, environmental effects were evaluated using the guidance in Regulatory Guide 1.207, Revision 1, which specifies the following:

Carbon and Low-Alloy Steels

- The formula provided in Appendix A of NUREG/CR-6909, Revision 1 (Reference 4.8.48), using the fatigue design curve for carbon and low alloy steel provided in NUREG/CR-6909, Revision 1 (Figure A.1 and A.2, respectively, and Table A.1).

Austenitic Stainless Steels

- The formula provided in NUREG/CR-6909, Revision 1, using the fatigue design curve for austenitic stainless steel provided in NUREG/CR-6909, Revision 1 (Figure A.3 and Table A.2).

The environmental fatigue screening calculation methodology is described below.

1. All component locations that have documented a cumulative usage factor (CUF) in the BFN current licensing basis were identified.
2. Locations not in contact with liquid reactor water at operating conditions were excluded from the screening.
3. For all included locations, the following was done:

   a. The technical rigor used to calculate the original CUF value was determined. For example, the location was evaluated to ASME Section III, Subsection NB-3600.

b. It was determined if the original CUF value is the result of “lumped” transient assumptions.

c. An 80-year CUF value was estimated, for screening purposes only, based on linear extrapolation of published 40-year or 60-year U values.

d. A maximum F_{en} was calculated based on material type, maximum temperature, and chemistry; and a screening 80-year EAF usage (CUF_{en}) value was calculated.

e. Locations with a screening CUF_{en} less than 1.0 were prescreened out.

4. Remaining locations that undergo essentially the same thermal and pressure transients during plant operations were grouped together into the same thermal zones.

5. Within each material type in a thermal zone, the following was performed:

   a. The location with the highest estimated screening 80-year CUF_{en} value was selected.

   b. The location with the 2nd highest estimated screening 80-year CUF_{en} value was also selected if its CUF_{en} was within 25% of the highest CUF_{en}.

   c. Detailed fatigue and EAF analyses in accordance with NUREG/CR-6909, Revision 1 were performed for selected locations.

This methodology resulted in the detailed EAF analysis of a large majority of component locations that have an identified CUF value in a BFN CLB stress report or evaluation and are in contact with reactor water. For example, of the 32 component locations that have an identified CUF value in a BFN CLB stress report or evaluation and for which EAF applies, 21 component locations were evaluated for detailed EAF analysis. These 21 component locations will be monitored by FatiguePro^{TM} during the subsequent period of extended operation. Also, locations that were eliminated were verified to have been originally evaluated to the same technical rigor as those locations which are selected.

In the BFN screening calculations, for each wetted material within a system, a new CUF value in air was computed using the applicable NUREG/CR-6909, Revision 1 fatigue curve and the alternating stress values from the existing ASME Code fatigue calculation. The F_{en} multipliers were computed based upon the applicable formula provided in NUREG/CR-6909, Revision 1 for each material using dissolved oxygen values that yielded the largest F_{en} values. Dissolved oxygen values were determined for different regions within the RPV and Class 1 piping systems using the EPRI BWRVIA radiolysis computer model. The model is designed to predict dissolved oxygen and dissolved hydrogen concentrations at various locations within the RPV and piping based upon chemical sampling and monitoring data. The reactor coolant dissolved oxygen values were significantly reduced by hydrogen water chemistry and noble metal injection strategies employed for each BFN unit, which were accounted for in the determination of the F_{en} multipliers. Each BFN unit was initially operated using Normal Water Chemistry (NWC), followed by Hydrogen Water Chemistry (HWC), then by the strategy of simultaneously employing HWC plus Noble Metal Chemical Addition (NMCA). The current strategy employs HWC plus Online Noble Chemistry (OLNC). Dissolved oxygen values were determined for each of these operating regimes (NWC, HWC, HWC + NMCA, and HWC + OLNC) for each region of the RPV and for each affected Class 1 piping system. Values that yield the highest F_{en} multipliers were chosen for each operating regime.

Environmental Fatigue Analyses

The 80-year projected cycles shown in Table 4.3.1-1, Table 4.3.1-2, and Table 4.3.1-3 were used as inputs in the environmental fatigue analyses. As discussed in Section 4.3.1, the 80 year projected CUF_{en} values in Table 4.3.1-4 conservatively use the larger number transient cycle projections from either Units 1, 2, or 3, so the results in Table 4.3.1-4 are applicable to all three units.

The environmental fatigue analyses described within this section will be incorporated into the CLB prior to the start of the subsequent period of extended operation. The environmental fatigue analyses will be managed by the Fatigue Monitoring program (B.3.1.1) using the FatiguePro^{TM} software, including periodic validation of cycles and water chemistry parameters that contribute to Fen, as discussed in Section 4.3.1. The Fatigue Monitoring program includes requirements that initiate corrective actions if any CUF or CUF_{en} values exceed 70 percent of the ASME Section III acceptance criterion. Corrective actions may include revision of the affected environmental fatigue analysis to qualify an increased number of cycles determined to bound 80 years of operation, repair, replacement, or establishing an inspection program using an approach acceptable to the NRC (such as an inspection program performed in accordance with Appendix L of ASME Code Section XI based on flaw tolerance analysis) prior to the CUF_{en} value exceeding the allowed value.

TLAA Disposition:

10 CFR 54.21(c)(1)(iii) - The Fatigue Monitoring program (B.3.1.1) is credited with managing the effects of environmental fatigue on the intended functions of all RPV and Class 1 piping components through the subsequent period of extended operation.

4.3.6 Replacement Steam Dryer Stress Report and Fatigue Evaluation

TLAA Description:

The reactor vessel steam dryers have been replaced on each BFN unit to support the EPU project. The replacement steam dryers, designed by GEH, are nonsafety-related items and are classified as Internal Structures as defined in the ASME Boiler and Pressure Vessel Code, Section III (1989 Edition no Addenda), Subsection NG Paragraph NG-1122. The replacement steam dryers are not components governed by ASME Boiler and Pressure Vessel Code, Section III, however the design was evaluated in 2015 and does comply with stress and fatigue criteria for core support structures defined in ASME Code Subsection NG-3000, with exceptions as described in NEDC-33824P, “Browns Ferry Replacement Steam Dryer Stress Analysis,” dated August 2015.

BWR steam dryers are subjected to flow induced vibration caused by cyclic acoustic pressures during normal operation. The steam dryers are expected to experience on the order of 1011 stress cycles during a steam dryer's typical 40 to 60 year life span. Therefore, high cycle fatigue contributes a majority of the steam dryer fatigue usage. The flow induced vibration fatigue evaluation described in NEDC-33824P for the replacement steam dryers is consistent with the ASME Boiler and Pressure Vessel Code, Section III requirements. Other cyclic loads associated with normal and upset design events, including pressure, transient loads, and thermal cycling, have not been significant contributors to fatigue damage and with the heavier replacement steam dryers are considered to add minimal fatigue usage. Therefore, the high cycle fatigue life is the major design consideration. These steam dryer structural analyses were performed assuming that the replacement steam dryers would be operated for 40 to 60 years. The NRC documented their review of the BFN replacement steam dryer analyses, including the associated fatigue analysis, in the NRC SE regarding the BFN EPU included in the NRC letter to TVA (Reference 4.8.52).

Since the evaluation for the replacement steam dryers assumed a certain number of stress cycles during the design life, it has been identified as TLAA that must be re-evaluated for the subsequent period of extended operation.

TLAA Evaluation:

A design analysis to calculate the fatigue of the replacement steam dryers was performed prior to installation at BFN. The replacement steam dryer design has been utilized at EPU power conditions in two other BWR/4 units, and one BWR/6 unit. This analysis includes consideration of the most limiting steam dryer acoustic pressure loads based on measurements taken at each BFN unit. The analysis calculated the stresses for the steam dryer components based on the currently licensed thermal power and extrapolates those to EPU power conditions based on scaling factors developed from trending power ascension data. Primary stress analyses for the load combinations were compared to ASME stress limits and shows that the replacement steam dryers will maintain structural rigidity during normal operation and as well as during transient and accident conditions.

The BFN Units 1, 2, and 3 replacement steam dryers were put in service in 2018 (for Unit 1 and Unit 3) and 2019 (for Unit 2). The period of subsequent extended operation would expire in 2053 for Unit 1, 2054 for Unit 2, and 2056 Unit 3. Given the 40-60 year period assumed in the structural analyses for the replacement steam dryers, the current structural analysis would remain valid as follows:

- until at least 2058 for the Unit 1 replacement steam dryer;
- until at least 2058 for the Unit 3 replacement steam dryer; and
- until at least 2059 for the Unit 2 replacement steam dryer.

TLAA Disposition:

10 CFR 54.21(c)(1)(i) - The replacement steam dryer fatigue evaluation remains valid through the subsequent period of extended operation.

4.3.7 Emergency Equipment Cooling Water System Weld Flaws Evaluation

TLAA Description:

Microbiologically induced corrosion was discovered in 1987 at BFN within Emergency Equipment Cooling Water (EECW) piping. Following this and microbiologically induced corrosion discoveries at other plants, a weld inspection program was initiated at BFN to determine the effects of microbiologically induced corrosion on the stainless-steel piping girth butt welds in the EECW system. The inspection program was implemented by performing radiography on a sample of EECW piping welds. Radiography had not been performed on these welds during installation, as it was not required by the applicable code and specifications. Based on the radiography results, 27 EECW welds had flaws larger than normally considered acceptable by the procedures contained in ASME Section XI. The existing analyses of these weld flaws, documented in site calculations, include a stress evaluation of the flawed welds and fatigue crack growth calculations. The fatigue crack growth calculations were based on a conservative projection of

125 cycles, which was determined to be bounding for the remainder of the plant operating life under the current renewed operating licenses (60 total years of operation). As such, these analyses are considered TLAAs that must be re-evaluated for the subsequent period of extended operation.

TLAA Evaluation:

The BFN EECW Weld Flaw Fatigue Cycle Monitoring procedure implements an administrative tracking system to ensure limiting number of fatigue cycles will not be exceeded at the select EECW locations and satisfies a BFN initial License Renewal commitment. This procedure tracks the total lifetime cycles of each affected weld flaw, and also provides compensatory measures to take in the event one or more weld flaws approaches the 125-cycle limit.

Seventeen of the 27 weld flaws were re-evaluated, and the number of cycles to exceed the allowable crack depth was increased from 125 to 2,600 cycles. This cycle limit is bounding for all 27 weld flaws, as it was calculated from the weld with the smallest number of allowable cycles (Weld 2-AC-09B, which corresponds to Residual Heat Removal Pump Room Coolers 2A and 2C) before reaching the allowable crack length. Due to this high cycle limit, the administrative tracking system provided by the EECW Weld Flaw Fatigue Cycle Monitoring procedure is no longer needed.

Historical cycle data is documented in the EECW Weld Flaw Fatigue Cycle Monitoring procedure. Cycle data from June 2002 to June 2013 was taken retroactively from the BFN Electronic Shift Operations Management System plant database. This data was conservatively projected backwards from June 2002 to September 1987 to establish the complete operational history for the tracked weld flaws. Cycle data was tracked from June 2013 through the present (May 2021) using the methodology described in the EECW Weld Flaw Fatigue Cycle Monitoring procedure.

The June 2013 through May 2021 cycle data documented in the EECW Weld Flaw Fatigue Cycle Monitoring procedure is used to determine the average rate of thermal cycling for each set of tracked EECW weld flaws, as this period of data is the most recent, the most accurately tracked and documented, and does not contain excessive conservatism. This average rate of thermal cycling is used to project the future number of thermal cycles for each set of EECW weld flaws from 2021 through the end of the subsequent period of extended operation.

The projected future cycles are combined with the historical data from the EECW Weld Flaw Fatigue Cycle Monitoring procedure to determine the total lifetime thermal cycles for each set of EECW weld flaws.

If the total is less than 2,600 cycles, then the analysis projected to the end of the subsequent period of extended operation will remain valid, satisfying 10 CFR 54.21(c)(1)(ii)

Table 4.3.7-1 below shows the historical cycle history, recent average rate of cycles per year, projected future cycles, and total lifetime cycles for each of the evaluated EECW weld flaws.

Table 4.3.7-1, Total Lifetime Thermal Cycles for EECW Weld Flaws

Description	Diesel Generator 1A Engine Coolers	Diesel Generator 1B Engine Coolers	Diesel Generator 1C Engine Coolers	Diesel Generator 1D Engine Coolers
Weld Flaw Numbers	1-2	3-4	5-6	7-8
Unit	1-2	1-2	1-2	1-2
Remaining Years of Operation	35(1)	35(1)	35(1)	35(1)
Total Cycles, 09/1987 - 07/2013	57	66	57	63
Total Cycles, 07/2013 - 05/2021	9	11	12	10
Cycle Rate, 2013 - 2021, Cycles/Year	1.125	1.375	1.5	1.25
Projected Future Cycles	40	49	53	44
Total Projected Lifetime Cycles	**106**	**126**	**122**	**117**
(1) BFN Unit 3 Technical Specification LCO 3.8.1.c requires the Units 1 and 2 Diesel Generators to be operable. As a result, the remaining years of operation for the Diesel Generator 1A through 1D Engine Coolers is 35, consistent with the end of subsequent period of extended operation for BFN Unit 3.				
Description	**Core Spray Pump Room Cooler 2A**	**Core Spray Pump Room Cooler 2B**	**RHR Pump Room Coolers 2A & 2C**	**RHR Pump Room Coolers 2B & 2 D**
Weld Flaw Numbers	9-11	12-15	16-17	18-21
Unit	2	2	2	2
Remaining Years of Operation	33	33	33	33
Total Cycles, 09/1987 - 07/2013	42	33	54	27
Total Cycles, 07/2013 - 05/2021	7	6	6	9
Cycle Rate, 2013 - 2021, Cycles/Year	0.875	0.75	0.75	1.125
Projected Future Cycles	29	25	25	38
Total Projected Lifetime Cycles	**78**	**64**	**85**	**74**
Description	**Diesel Generator 3B Engine Coolers**	**Diesel Generator 3C Engine Coolers**	**Diesel Generator 3D Engine Coolers**	
Weld Flaw Numbers	22-23	24-26	27	
Unit	3	3	3	
Remaining Years of Operation	35	35	35	
Total Cycles, 09/1987 - 07/2013	45	72	72	
Total Cycles, 07/2013 - 05/2021	8	5	11	
Cycle Rate, 2013 - 2021, Cycles/Year	1	0.625	1.375	
Projected Future Cycles	35	22	49	
Total Projected Lifetime Cycles	**88**	**99**	**132**	

As shown in Table 4.3.7-1 above, the total lifetime thermal cycles through the end of subsequent period of extended operation is expected to remain below 2,600 for all 27 tracked EECW weld flaws. Therefore, the analysis for those 27 welds projected to the end of the subsequent period of extended operation is determined to remain valid, satisfying 10 CFR 54.21(c)(1)(ii).

TLAA Disposition:

10 CFR 54.21(c)(1)(ii) -The aging effects of thermal cycles on the 27 EECW weld flaws have been projected to the end of the period of extended operation and are determined to remain below the allowable limit.

4.3.8 Core Shroud Support Fatigue Analysis Reevaluation

TLAA Description:

The BFN core shroud support is a stainless-steel cylinder that forms a barrier between the outside of the shroud and the inside of the reactor vessel. BWR core shroud supports are subject to high temperature and harsh radiation environments during operation. They are susceptible to metal fatigue in the same manner as any other steel component.

Review of the CLB identified a vessel stress and fatigue evaluation performed for EPU (Reference 4.8.59). The document also identifies the 40-year CUF values for the core shroud support as 0.17. Based on screening performed in the report, it was determined that further evaluation of the core shroud support was not required (based on the low CUF).

TLAA Evaluation:

The 80-year environmental fatigue analysis contains a CUF and CUF_{en} calculation for the core shroud support. At the end of the subsequent period of extended operation, the calculated CUF is 0.0730 and the CUF_{en} is 0.256. Both of these values are less than the requirement of 1.0.

TLAA Disposition:

10 CFR 54.21(c)(1)(ii) - The core shroud support fatigue analysis has been projected through the subsequent period of extended operation.

4.3.9 BFN Unit 3 Core Spray T-Box Repair Fatigue Evaluation

TLAA Description:

BFN Unit 3 has installed a core spray T-box repair. An explicit fatigue analysis was performed for this modification assuming a 40-year lifetime. For initial license renewal, the analysis was projected to 60 years. The fatigue usage factor was calculated under two different conditions: the core spray piping remained attached to the T-box; and the core spray piping completely separated from the T-box.

Since this analysis was identified as a TLAA for the initial license renewal project and validated for 60 years, it has been identified as a TLAA that must be re-evaluated for the subsequent period of extended operation.

TLAA Evaluation:

The fatigue usage for the Unit 3 configuration where the piping is attached to the T-box was calculated to be 0.022 using 40-year design cycles. Based on a date of November 1995 (Unit 3 restart) for the T-box repair a 40 year license expiration date of July 2016 for Unit 3 (Reference 4.8.35), the maximum time the repair will be in service at 80 years of plant operation will be 61 years. A comparison of Unit 3 projected 80 year cycles to design cycles indicates

80 year projected cycles do not exceed 2 times the number of design cycles. Without having the details of the fatigue evaluation, usage can be conservatively projected by multiplying the usage based on 40 year design cycles by a factor of 2 for 80 years. The resulting projected fatigue usage would therefore be 0.044. Because usage factor for this location is calculated without explicit consideration of the 80-year cycle projections, using updated 2022 cycle counts would have no effect on the projected fatigue usage.

The fatigue usage for the Unit 3 configuration where the piping has become detached from the T-box was initially calculated to be greater than 1.0 and was subsequently reduced to 0.9 based on an assumption of reduced cycles associated with the remaining life of the plant. Based on a date of November 1995 (Unit 3 restart) for the T-box repair and a 40-year license expiration date of July 2016 for Unit 3 (Reference 4.8.35), the maximum time the repair will be in service at 60 years of operation would be 41 years and for 80 years of plant operation will be 61 years.

Inspections to date confirm that the piping remains attached to the T-box. Therefore, the relevant fatigue usage to be evaluated is that of the attached piping configuration.

The fatigue usage for the Core Spray T-box repair has been conservatively projected to 80 years of plant operation. This is less than the allowable fatigue usage of 1.0 and is acceptable.

<u>TLAA Disposition:</u>

10 CFR 54.21(c)(1)(iii) - To ensure fatigue usage remains acceptable through the subsequent period of extended operation, ongoing inspections to ensure the Core Spray piping has not become detached will be performed in accordance with the BWR Vessel Internals program (B.2.1.7) and monitoring of fatigue in accordance with the Fatigue Monitoring program (B.3.1.1) will be performed.

4.3.10 BFN Unit 3 Core Spray Lower Line Section Replacement Fatigue Evaluation

<u>TLAA Description:</u>

A sectional replacement of the lower core spray sparger line was installed on BFN Unit 3. The repair is a bolted replacement of the lower section of the core spray piping in the downcomer region. The sectional replacement was only installed at 7.5°.

For initial license renewal, the design life of this repair was specified as 40 years and would not exceed that lifetime before the end of the 60-year lifetime. Since this analysis was identified as a TLAA for the initial license renewal project and validated for 60 years, it has been identified as a TLAA that must be re-evaluated for the subsequent period of extended operation.

<u>TLAA Evaluation:</u>

For the LRA, the maximum reported fatigue usage of the lower Core Spray line sectional replacement was calculated to be 0.45 using 40-year design cycles. Based on a date of September 1998 for the lower line replacement and a 40 year license expiration date of July 2016 for Unit 3 (Reference 4.8.35), the maximum time the replacement will be in service at 80 years of plant operation will be 58 years for Unit 3. A comparison of Unit 3 projected 80 year cycles to design cycles indicates 80 year projected cycles do not exceed 2 times the number of design cycles. The usage can be conservatively projected by multiplying the usage based on 40 year design cycles by a factor of 2 for 80 years. The resulting projected fatigue usage would therefore be 0.9. This fatigue usage value is valid as long as inspections do not indicate detachment of the replacement piping. Because usage factor for this location is calculated without explicit consideration of the 80-year cycle projections, using updated 2022 cycle counts would have no effect on the projected fatigue usage.

The fatigue usage for the lower line section replacement has been conservatively projected to 80 years of plant operation. This is less than the allowable fatigue usage of 1.0 and is acceptable.

TLAA Disposition:

10 CFR 54.21(c)(1)(iii) - To ensure fatigue usage remains acceptable through the subsequent period of extended operation, ongoing inspections to ensure the Core Spray piping has not become detached will be performed in accordance with the BWR Vessel Internals program (B.2.1.7) and monitoring of fatigue in accordance with the Fatigue Monitoring program (B.3.1.1) will be performed.

4.3.11 Jet Pump to Core Shroud Support Plate Fatigue Evaluation

TLAA Description:

The BFN core shroud support plate and jet jump diffuser weld join the components and provides a barrier between the downcomer water and the jet pump flow. This a location where susceptibility to fatigue is a concern due to dynamic forces from jet pump flow and thermal stresses of the interfacing liquid temperature differences.

This analysis was identified as a TLAA for the initial license renewal project and validated for 60 years, it has been identified as a TLAA that must be re-evaluated for the subsequent period of extended operation.

TLAA Evaluation:

The calculated usage of 0.35 at the jet pump diffuser to core shroud support plate is based on original plant design documentation. The prior analysis uses a very conservative approach where the peak strain was calculated based on an assumption that the reactor internals were instantaneously cooled to a temperature of 300°F while the vessel was maintained at a temperature of 550°F. The strain range at this point was then used to establish the number of allowable cycles for other applicable transients.

An analysis has been prepared to project the fatigue at the jet pump to core shroud support plate weld location. Other than the DBA event, the majority of usage is due to HPCI, Startup and Shutdown transient cycles as shown in Table 4.3.11-1 below.

Table 4.3.11-1, Jet Pump to Core Shroud Fatigue Usage Update for 80 Years at Limiting Location D

Transient	Allowable Cycles	Projected Cycles(1)	Usage
HPCI-Startup	150	104	0.693
Startup-Shutdown	880	100(1)	0.114
Sudden Start of Cold Pump	740	1	0.001
DBA	10	1	0.100

Table 4.3.11-1, Jet Pump to Core Shroud Fatigue Usage Update for 80 Years at Limiting Location D (Continued)

Transient	Allowable Cycles	Projected Cycles(1)	Usage
Total Usage			0.908
(1) 100 = 204 Startup cycles - 104 HPCI Startup cycles removed from first row.			

The fatigue usage for the Jet Pump Diffuser to Core Shroud Support Plate has been conservatively projected to 80 years of plant operation. The 80-year projected fatigue usage is 0.908. This is less than the allowable fatigue usage of 1.0 and is acceptable.

TLAA Disposition:

10 CFR 54.21(c)(1)(iii) - To ensure fatigue usage remains acceptable through the subsequent period of extended operation, monitoring of fatigue in accordance with the Fatigue Monitoring program (B.3.1.1) will be performed.

4.4 ENVIRONMENTAL QUALIFICATION OF ELECTRIC EQUIPMENT

4.4.1 Environmental Qualification of Electric Equipment

TLAA Description:

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) for BFN. The NRC has established nuclear station environmental qualification (EQ) requirements in 10 CFR 50.49. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical components located in harsh plant environments are qualified to perform their safety function in those harsh environments after the effects of in-service aging. Harsh environments are defined as those areas of the plant that could be subject to the harsh environmental effects of a LOCA, HELB, or post-LOCA radiation. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification.

Environmental Qualification Program Background

The Environmental Qualification of Electric Equipment program meets the requirements of 10 CFR 50.49 for the applicable electrical components important to safety. 10 CFR 50.49 defines the scope of components to be included, requires the preparation and maintenance of a list of in-scope components, and requires the preparation and maintenance of a qualification file that includes component performance specifications, electrical characteristics and the environmental conditions to which the components could be subjected. The electrical equipment, within the scope of 10 CFR 50.49, at BFN was originally qualified to the acceptance criteria specified in either 1) Category I of NUREG-0588 (Institute of Electrical Engineers (IEEE) 323-1974) or 2) Category II of NUREG-0588 or the Division of Operating Reactor guidelines of NRC Inspection and Enforcement Bulletin 79-01B (IEEE 323-1971). Replacement components are qualified in accordance with 10 CFR 50.49 (Reference 4.8.57).

Aging evaluations for electrical components in the Environmental Qualification of Electric Equipment program that specify a qualification of at least 60 years are TLAAs for the subsequent license renewal because the criteria contained in 10 CFR 54.3 are met.

TLAA Evaluations:

Under 10 CFR 54.21(c)(1)(iii), the Environmental Qualification of Electric Equipment program (B.3.1.3), which implements the requirements of 10 CFR 50.49 is an aging management program for Subsequent License Renewal.

Reanalysis of an aging evaluation to extend the qualifications of components is performed as part of the Environmental Qualification of Electric Equipment program. The program complies with all applicable regulations and manages equipment thermal, radiation, and cyclic aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. 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). Environmentally qualified equipment must be refurbished, replaced, or have its qualification extended prior to reaching the aging limits established in the aging evaluation.

The TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii), which states that the effects of aging will be adequately managed for the subsequent period of extended operation, because the Environmental Qualification of Electric Equipment program will manage the aging effects of the components associated with the environmental qualification TLAA.

NUREG-2191 states that the NRC evaluated the EQ program based on 10 CFR 50.49, and determined that it is an acceptable aging management program to address environmental qualification according to 10 CFR 54.21(c)(1)(iii).

The evaluation referred to in NUREG-2192 contains sections on “EQ Component Reanalysis Attributes, Evaluation, and Technical Basis” that is the basis of the description provided below.

Component Reanalysis Attributes

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

Analytical Methods

The Environmental Qualification of Electric Equipment program uses the same analytical models in the reanalysis of an aging evaluation as those previously applied during the prior evaluation. The Arrhenius methodology is an acceptable thermal model for performing a thermal aging evaluation. The analytical method used for a radiation aging evaluation is to demonstrate qualification for the total integrated dose, which is the normal radiation dose for the projected installed life plus accident radiation dose. For subsequent license renewal, one acceptable method of establishing the 80-year normal radiation dose is to multiply the 60-year normal radiation dose by 1.33 (that is, 80 years/60 years). The result is added to the accident radiation dose to obtain the total integrated dose for the component. For cyclical aging, a similar approach may be used. Other models may be justified on a case-by-case basis.

Data Collection and Reduction Methods

The chief method used for a reanalysis per the Environmental Qualification of Electric Equipment program is reduction of excess conservatism in the component service conditions used in the prior aging evaluation, including temperature, radiation, and cycles. Temperature data used in an aging evaluation should be based on plant design temperatures or on actual plant temperature data. When used, plant temperature data can be obtained in several ways, including monitors used for technical specification compliance, other installed monitors, measurements made by plant operators during rounds, and temperature sensors on large motors. A representative number of temperature measurements are evaluated to establish the temperatures used in an aging evaluation. Plant temperature data may be used in an aging evaluation in different ways, such as: (a) directly applying the plant temperature data in the evaluation; or (b) using the plant temperature data to demonstrate conservatism when using plant design temperatures for an evaluation. Any changes to material activation energy values as part of a reanalysis must be justified. Similar methods of reducing excess conservatism in the component service conditions used in prior aging evaluations can be used for radiation and cyclical aging. Operating Experience can also provide additional basis to justify changes in the qualification of the equipment.

Underlying Assumptions

The Environmental Qualification of Electric Equipment program component aging evaluations contain sufficient conservatism. Additionally, plant modifications that have potential impact to the Environmental Qualification of Electric Equipment program are evaluated during the modification design process to determine the impact of the plant modification on the Environmental Qualification of Electric Equipment program. When unexpected adverse conditions are identified during operational or maintenance activities that affect the normal operating environment of a qualified component, the affected EQ component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions.

Acceptance Criteria and Corrective Action

Under the Environmental Qualification of Electric Equipment program, the reanalysis of an aging evaluation could extend the qualified life of the component. If the qualification cannot be extended by reanalysis, the component must be refurbished, replaced, or requalified prior to exceeding the period for which the current qualification remains valid. A reanalysis is to be performed in a timely manner such that sufficient time is available to refurbish, replace, or requalify the component if the reanalysis is unsuccessful.

Ongoing Qualification

Under the Environmental Qualification of Electric Equipment program, ongoing qualification techniques may be implemented when assessed margins, conservatisms, or assumptions do not support reanalysis of an EQ component of electric equipment important to safety. The requirements of 10 CFR 50.49 provide methods that are used to evaluate and maintain electric equipment qualification, including qualified life, for the subsequent period of extended operation.

<u>TLAA Disposition:</u>

10 CFR 54.21(c)(1)(iii) - The effects of aging on the intended function(s) will be adequately managed through the subsequent period of extended operation in accordance with the Environmental Qualification of Electric Equipment program (B.3.1.3).

4.5 CONCRETE CONTAINMENT TENDON PRESTRESS ANALYSIS

The BFN containment does not have pre-stressed tendons. As such, this topic is not a TLAA.

4.6 PRIMARY CONTAINMENT FATIGUE ANALYSES

The primary containment vessels for BFN Units 1 and 2 were designed in accordance with the ASME Code Section III 1965 Edition with addenda up through Winter 1966. The primary containment vessel for Unit 3 was designed in accordance with the ASME Code Section III 1965 Edition with addenda up through Summer 1967. Subsequently while performing large-scale testing for the Mark III Containment System and in-plant testing for the Mark I Containment Systems, new suppression chamber (also referred to as the torus) hydrodynamic loads were identified. These additional loads result from blowdown into the suppression chamber during a postulated loss-of-coolant accident and during main steam relief valve operation during plant transients. The results of analyses of these effects were presented in the BFN Torus Integrity Long-Term Program Plant Unique Analysis Report. The suppression chamber, and suppression chamber vents including the vent headers and downcomers were modified in order to re-establish the original design safety margins. Allowable stresses for these components were in compliance with Subsection NE of the 1977 ASME Boiler and Pressure Vessel Code, Section III, including Summer 1977 Addenda.

The BFN Torus Integrity Long-Term Program Plant Unique Analysis Report describes several fatigue analyses. The following were evaluated to be TLAAs:

- Fatigue of suppression chamber, vents, and downcomers (Section 4.6.1)
- Fatigue of torus attached pipe and SRV discharge lines (Section 4.6.2)
- Fatigue of vent line and process penetration bellows (Section 4.6.3)

These TLAAs will require evaluation for the subsequent period of extended operation.

4.6.1 Suppression Chambers, Vents and Downcomers Fatigue Analyses

TLAA Description:

Subsequent to the original design, elements of the BFN Unit 1, Unit 2, and Unit 3 primary containments were reanalyzed in response to discoveries, by General Electric and others, of unevaluated loads due to design basis events and Safety Relief Valve (SRV) discharge. The load definitions include assumed pressure and temperature transient cycles resulting from SRV discharge and design basis LOCA events. The BFN Torus Integrity Long-Term Program Plant Unique Analysis Report describes fatigue analyses of the suppression chamber and suppression chamber vents, including the vent headers and downcomers. The analyses assumed a limited number of main steam SRV actuations, based on plant data extrapolated to 40 years. Therefore, these analyses are TLAAs.

The following Unit 1, Unit 2, and Unit 3 primary containment structures and associated components have been identified as TLAAs that require evaluation for the subsequent period of extended operation:

- Unit 1, Unit 2, and Unit 3 Suppression Chamber
- Unit 1, Unit 2, and Unit 3 Suppression Chamber Vents, including vent headers and downcomers

TLAA Evaluation:

The primary containment fatigue reanalysis used, as input, the following transient cycles:

- SRV Lifts (Tables 4.3.1-1, 4.3.1-2, and 4.3.1-3 transients 36 and 37)
- Operating Basis Earthquake (Tables 4.3.1-1, 4.3.1-2, and 4.3.1-3 transient 18)

Of these, the SRV lift transient is the only transient that is associated with normal operations while the remaining transients are either faulted or upset events. The BFN Torus Integrity Long-Term Program Plant Unique Analysis Report assumed 500 SRV actuations during 40 years of normal operations and the contribution from the postulated worst-case LOCA. The worst-location fatigue CUFs were calculated to be:

0.681, in the vent headers where they intersect with the downcomers

0.373, at the downcomer/tiebar intersection

0.37, for the suppression chamber restraint snubbers.

Since only the SRV load cases contribute to fatigue during normal operation, normal operation may continue so long as the contribution from SRV actuations has not exceeded 1.0 minus the contribution expected from the postulated worst-case LOCA. To ensure that corrective actions are taken before CUFs approach 1.0, BFN will manage the high CUF location using the Fatigue Monitoring program (B.3.1.1) to monitor SRV actuations.

The original Bergen Patterson suppression chamber restraint hydraulic snubbers which were evaluated during the initial license renewal (60 years) were replaced with Lisega hydraulic snubbers not long after the license extension was approved (for all units). The original Bergen Patterson snubbers suffered seal leakage issues which would result in decreased capacity, necessitating their replacement. Additionally, the previous fatigue analysis was only performed because the Bergen Patterson snubbers were unable to be functionally tested in place and could not be removed without great effort. The safety determination for the replacement snubbers is now based on functional testing described in BFN procedural documents. Based on this and 10 CFR 54.3 TLAA screening criteria 1 through 6, the suppression chamber restraint snubbers are not a TLAA for the BFN SLR.

It has been estimated for BFN, based on historical cycle tracking information, that the actual number of SRV actuations will not exceed 500 for Units 1, 2, and 3 during the subsequent period of extended operation. The estimated number of SRV actuations from initial startup through the end of the subsequent period of extended operation (80 total years of operation) is estimated to be approximately 190 for Unit 1, 318 for Unit 2, and 239 for Unit 3.

TLAA Disposition:

10 CFR 54.21(c)(1)(iii) - The Fatigue Monitoring program (B.3.1.1) is credited with managing these primary containment fatigue TLAAs through the subsequent period of extended operation.

4.6.2 Torus Attached Piping and Safety Relief Valve Discharge Lines Fatigue Analyses

TLAA Description:

There are 13 main steam SRVs to allow blowdown from the main steam piping in the drywell to the suppression pool via individual discharge lines passing through the main vents. The main steam SRV discharge piping enters the suppression chamber through penetrations in the suppression chamber vent header and the steam is discharged to the suppression pool water through a T-quencher attached to the suppression chamber.

Additionally, there are a number of external piping systems attached to the suppression chamber shell.

The Plant Unique Analysis Report describes that a fatigue evaluation of the torus attached piping, including the MSRV piping, was performed per a program developed by the Mark I Owner's Group. This analysis included the effects of mechanical load cycling in addition to the thermal expansion. The results justified fatigue life acceptability for torus attached piping, including the SRV suppression chamber piping.

These analyses assume a limited number of SRV actuations throughout the 40-year life for the plant and are therefore TLAAs.

TLAA Evaluation:

For the initial License Renewal, the predicted 60-year cumulative usage factor was less than 0.666 (worst-case CUF is 0.35 x 60/40 = 0.53) for the main steam SRV discharge lines, T-quenchers, the main steam SRV discharge line penetrations through the vent lines, torus attached piping systems, and the associated penetration locations. The torus attached piping and main steam SRV discharge lines fatigue analyses were predicted to have a large margin in their design fatigue limit during the period of extended operation. As such, the analyses were determined to remain valid for the period of extended operation.

For the main steam SRV discharge lines, T-quenchers, the main steam SRV discharge line penetrations through the vent lines, torus attached piping systems, and the associated penetration locations, for Units 1, 2, and 3, the analysis remains valid for the subsequent period of extended operation as the estimated number of SRV actuations does not exceed 500.

TLAA Disposition:

10 CFR 54.21(c)(1)(i) - For BFN Units 1, 2, and 3, the discussed analyses remain valid for the period of extended operation.

4.6.3 Containment Vent Lines And Process Penetration Bellows Fatigue Analyses

TLAA Description:

The suppression chamber vent line bellows are flexible expansion joints allowing movement of the main vent pipes through the suppression chamber wall while maintaining the required pressure boundary. The analysis of the suppression chamber bellows was performed in accordance with Standards of the Expansion Joint Manufacturers Association, Inc. as described in the Plant Unique Analysis Report. These analyses assume a limited number of thermal cycles throughout the 40-year life for the plant and are TLAAs.

Containment pipe penetrations that must accommodate thermal movement have expansion bellows. The bellows are designed for a minimum number of operating thermal cycles over the design life at containment normal, test, and limiting design pressures. These analyses also assume a limited number of thermal cycles throughout the 40-year life for the plant and are therefore TLAAs.

TLAA Evaluation:

The suppression chamber vent line bellows allows differential movement of the vent system and suppression chamber to occur without developing significant interaction loads. As described in FSAR Section C.5.2, the design life of the bellows is 7000 cycles.

Containment process piping expansion joints between the drywell shell penetrations and process piping are the only ones subject to significant thermal expansion and contraction. As described in FSAR Section C.5.2, these containment penetration process bellows have been designed for 7000 cycles.

For the initial BFN LRA, the predicted number of thermal cycles for piping analyses was proportionally increased to less than 1650, which is less than 25% of the 7000-cycle threshold limit. The suppression chamber bellows and the containment penetration bellows fatigue analyses were predicted to have a large margin to their design fatigue limit during the period of extended operation. As such, the analyses were determined to remain valid for the period of extended operation.

For the subsequent period of extended operation, the number of thermal cycles for piping analyses would be proportionally increased to less than 2200, which is approximately 31% of the 7000-cycle threshold limit. The fatigue analyses for the subsequent period of extended operation were determined to remain valid for the 80-year plant life.

TLAA Disposition:

10 CFR 54.21(c)(1)(i) - The primary containment vent lines and process penetration bellows fatigue analyses remain valid through the subsequent period of extended operation.

4.7 OTHER PLANT-SPECIFIC TIME-LIMITED AGING ANALYSES

This section evaluates:

- Reactor Building Crane Cyclic Loading Analysis (Section 4.7.1)
- Radiation Degradation of Drywell Expansion Gap Foam (Section 4.7.2)
- BFN Unit 2 RPV Axial Weld Flaw (Section 4.7.3)

Some TLAAs which were included in the plant-specific section of the LRA (Reference 4.8.28) have been relocated into their associated subsection (if applicable). Examples would be that the stress relaxation of the core support plate rim bolts was moved to Section 4.2.

Three plant-specific TLAAs were removed from the LRA in response to NRC Request for Additional Information (Reference 4.8.45). Accordingly, these items have not been identified as TLAAs during the subsequent period of extended operation.

4.7.1 Reactor Building Crane Cyclic Loading Analyses

TLAA Description:

There is one 125-ton Reactor Building overhead crane with a 5-ton auxiliary hoist, which serves the three reactor units at BFN (Reference 4.8.24). There is a primary drum for the main hook and a secondary drum for the auxiliary hook. The Reactor Building overhead crane is designed to meet the applicable criteria and guidelines of Chapter 2-1 of ANSI B30.2-1976 and Crane Manufacturers Association of America (CMAA) Specification 70-1975 (Guideline 7 of Reference 4.8.25). For cyclic loading, CMAA 70 specifies that a crane classified as Service Class A1 is limited to 100,000 loading cycles (i.e., 100,000 lifts at rated capacity) over the design life.

Since the maximum number of load cycles over the life of a crane, specified in CMAA Specification 70, provides a basis for acceptability for fatigue over the life of a crane, these analyses are considered TLAAs that must be re-evaluated for the subsequent period of extended operation.

TLAA Evaluation:

The BFN Reactor Building overhead crane handles shield plugs, reactor vessel and drywell heads, steam dryer and separator, spent fuel casks, equipment for the service and maintenance of the reactors, and equipment which is received or shipped through the equipment access lock. The crane was also used during plant construction and is expected to be used during decommissioning. For the BFN initial license renewal, the total number of expected cycles for this crane over the entire life including construction, 60-years of operation for all three units, and decommissioning, was conservatively estimated at less than 1000 lift cycles at rated capacity and less than 21,000 lift cycles total. For the subsequent license renewal of an additional 20 years, these values are prorated to be less the 1333 lift cycles are rated capacity and less than 28,000 lift cycles total.

In addition, the number of Reactor Building overhead crane cycles are increased to account for lift cycles associated with spent fuel dry-cask storage campaigns and considered a starting date of 2004. For the spent fuel dry-cask storage campaigns, the yearly average Reactor Building overhead crane lifts is less than 10 rated capacity lift cycles and less than 985 lift cycles total.

These spent fuel dry-cask storage campaigns are to extend 5 years past the end of the subsequent period of extended operation (i.e., 2056 for BFN Unit 3). Considering 57 years of spent fuel dry-cask storage campaigns at BFN (2004 to 2056 plus 5 years), the resulting Reactor Building overhead crane lifts associated with these storage campaigns is less than 570 rated capacity lift cycles and less than 56,145 lift cycles total.

The resulting 80-year projected number of cycles for the Reactor Building overhead crane is less than 1903 rated capacity lift cycles and less than 84,145 lift cycles total. The 80-year projected number of lift cycles is less than the minimum allowable design value of 100,000 rated capacity lift cycles. Therefore, the Reactor Building overhead crane cyclic loading analysis remains valid for 80 years of plant operation.

TLAA Disposition:

10 CFR 54.21(c)(1)(i) - The projected number of load cycles associated with the Reactor Building overhead crane are less than the allowable design value. Therefore, the TLAA remains valid through the subsequent period of extended operations.

4.7.2 Radiation Degradation of Drywell Expansion Gap Foam Analysis

TLAA Description:

The steel drywell shell is enclosed in reinforced concrete for shielding purposes and to provide additional resistance to deformation and buckling of the drywell over areas where the concrete backs up the steel shell. Above the transition zone, the drywell is separated from the reinforced concrete by a gap of approximately 2 inches. This gap is filled with polyurethane foam. As described in FSAR Section 5.2.3.2, irradiation tests have shown that no change in the resilient characteristics will take place for exposures up to $1.0x10^8$ Rads. The effect of a postulated increase in the foam stiffness resulting from radiation dose is a TLAA.

TLAA Evaluation:

The polyurethane foam material was chosen for its resistance to the environmental conditions likely to exist during its service life. Polyurethane foam samples, similar to those used in the gap, were irradiated in a test lab at various levels. The test results established that there was no detectable change in resilience below $1.0x10^8$ Rads. The original design considered the effects of a 40-year lifetime dose of $1.0x10^7$ Rads on the foam material, followed by a design basis LOCA that would expose the foam to $2.0x10^7$ Rads during the first 12 hours after which the drywell would begin to contract as the temperature decreases. Since the projected exposure was less than the tested exposure, the resilient characteristics of the polyurethane foam were projected to remain intact during the 40-year design life (Reference 4.8.28).

For the initial License Renewal, an analysis of the effect of dose on the foam for the additional 20 years of extended operation demonstrated that the maximum total dose of remained less than $1.0x10^8$ Rads for a 60-year license (Reference 4.8.28).

For the subsequent period of extended operation, another 20 years of extended operation were considered to evaluate the 80-year lifetime dose on the foam. The maximum dose after 80 years of operation and a design basis LOCA was less than the qualified dose of $1.0x10^8$ Rads. Therefore, the polyurethane foam is projected to remain resilient for an 80-year license.

TLAA Disposition:

10 CFR 54.21(c)(1)(ii) - The analysis of the effect of radiation dose on the drywell expansion gap foam has been projected through the subsequent period of extended operation.

4.7.3 BFN Unit 2 Reactor Vessel Axial Weld Flaw

TLAA Description:

During the BFN Unit 2 refuel outage 21, ultrasonic examination of the BFN Unit 2 reactor vessel, an indication in a vertical weld was identified that exceeds the acceptance standards of ASME Code, Section XI, IWB-3500. A flaw evaluation per the requirements of IWB-3600 was required.

The vertical weld flaw meets the criteria of 10 CFR 54.3(a) and is considered a TLAA for the subsequent period of extended operation.

TLAA Evaluation:

The indication is characterized as a planar flaw and is treated as a subsurface flaw per the criteria of IWA-3320 and Figure IWA-3320-1. The analysis using cycle projections from 2018 bounds the analysis using 2022 cycle projections.

The projected 64 EFPY fluence information was established to determine fracture toughness for vertical weld V-3-A in the BFN Unit 2 reactor vessel. The peak fluence value was calculated to occur at the lowest elevation of the weld flaw and had a value of 1.92E+15 n/cm^2 which is well below the established embrittlement fluence threshold of 1.0E+17 n/cm^2. This would suggest that the effects of embrittlement need not be considered in determining the fracture toughness. However, for conservatism, the effects of embrittlement on changes in toughness properties were considered using the embrittlement prediction methods for the threshold fluence level.

The vessel material exhibits upper-shelf behavior for all temperatures above 134.1°F which coincides with the upper-shelf cut-off limit of 220 ksi√in. Current procedures establish a minimum temperature of 200.6°F up to normal operating pressure, which is consistent with the P-T Limits Curve (Reference 4.8.36, Figure 3.4.9-2) at 38 EFPY. This value provides significant conservatism relative to the temperature of 134.1°F where upper-shelf behavior temperature occurs at a fluence of 64 EFPY.

Using the structural factors (i.e., margin) imposed by IWB-3612 for acceptance criteria based on applied stress intensity factor, the allowable fracture toughness for normal (Levels A and B) conditions is $220/\sqrt{10} = 69.57$ ksi-in$^{1/2}$. For emergency and faulted (Levels C and D) conditions, the allowable fracture toughness is $220/\sqrt{2} = 155.56$ ksi-in$^{1/2}$. Service Level A/B was determined to be controlling for fracture toughness.

Using the methods of ASME Code, Section XI, IWB-3610, the flaw is evaluated to demonstrate required margins against brittle failure. An allowable applied stress intensity factor of 69.57 ksi-in$^{1/2}$ or less would maintain the Code required (K_{IC} / K_I) margin of conditions $\sqrt{10}$ to prevent brittle failure for Service Levels A and B. The stress intensity factor characterizes the crack driving force when using the IWB-3610 linear elastic fracture mechanics methods. The calculated allowable flaw half-depth is 1.7156 inch.

Based on the flaw evaluation of the indication in the BFN Unit 2 reactor vessel V-3-A vertical weld using ASME Code Section XI, IWB-3600, it will take 84 years for the as-found flaw with an initial half depth of 1.6 inch to propagate to the allowable half-depth of 1.7156 inch based on the 64 EFPY fluence. Acceptable margin to the allowable flaw size should be verified as part of ongoing periodic ASME Code Section XI Inservice Inspections.

TLAA Disposition:

10 CFR 54.21(c)(1)(iii) - The effects of aging on the intended function of the reactor vessel vertical weld V-3-A will be adequately managed through ongoing periodic inspections in accordance with ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B.2.1.1).

4.8 REFERENCES

4.8.1 10 CFR 54, Requirements for Renewal of Operating Licenses for Nuclear Power Plants

4.8.2 NUREG-2192, Revision 0, Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants

4.8.3 NUREG-2191, Revision 0, Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report

4.8.4 NEI 95-10, Revision 6, Industry Guideline for Implementing the Requirements of 10 CFR 54, the License Renewal Rule

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4.8.6 10 CFR 50.12, Specific Exemptions

4.8.7 10 CFR 50.60, Acceptance Criteria for Fracture Prevention Measures for Lightwater Nuclear Power Reactors for Normal Operation

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4.8.9 10 CFR 50, Appendix H, Reactor Vessel Material Surveillance Program Requirements

4.8.10 BWRVIP-114-A, BWR Vessel and Internals Project, RAMA Fluence Methodology Theory Manual, 1019049, Final Report, June 2009 (CONTAINS PROPRIETARY INFORMATION)

4.8.11 NEDC-32983P-A, Rev. 2, Licensing Topical Report, General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluations, January 2006 (CONTAINS PROPRIETARY INFORMATION)

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4.8.15 NRC letter, H. N. Berkow to G. B. Stramback, Final Safety Evaluation Regarding Removal of Methodology Limitations for NEDC-32983P-A, “General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation” (TAC No. MC3788), November 17, 2005

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4.8.17 NRC Regulatory Guide 1.190, Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence, March 2001

4.8.18 Browns Ferry Nuclear Plant Units 1, 2, and 3 Technical Specification 3.4.9, Reactor Coolant System Pressure and Temperature Limits

4.8.19 Browns Ferry Nuclear Plant, Units 2 and 3 - Request for ASME Code, Section XI, Alternatives 2-ISI-30 and 3-ISI-27 for the Periods of Extended Operation regarding Reactor Pressure Vessel Circumferential Shell Weld Examinations (CAC Nos. MF7795 and MF7796), ADAMS Accession No. ML17045A772

4.8.20 Browns Ferry Nuclear Plant, Unit 1 - Alternative Relief Request 1-ISI-27 for Relief from the Reactor Vessel Circumferential Weld Examination Requirements of the ASME Code (CAC No. MF6401), ADAMS Accession No. ML16020A115

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4.8.22 BWRVIP-329-A, BWR Vessel and Internals Project, Updated Probabilistic Fracture Mechanics Analyses for BWR RPV Welds to Address Extended Operations, 3002022650, Final Report, December 2021 (CONTAINS PROPRIETARY INFORMATION)

4.8.23 Final Safety Evaluation by the Office of Nuclear Reactor Regulation for Boiling Water Reactor Vessel and Internals Program Topical Report BWRVIP-329, Updated Probabilistic Fracture Mechanics Analyses for BWR RPV Welds to Address Extended Operations, NRC, August 2019, EPID: L-2019-TOP- 0034 (Note: This SE is contained within BWRVIP-329-A on pages xi through xxiv)

4.8.24 BFN FSAR Section 12.2.2.5, Reactor Building Crane

4.8.25 BFN FSAR Appendix C, Section C.8.4.1, BFN Commitments in Response to NUREG-0612, Section 5.1.1

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4.8.40 Letter from William H. Bateman, USNRC, to Bill Eaton, BWRVIP Chairman; Safety Evaluation of Proprietary EPRI Reports, BWRVIP RAMA Fluence Methodology Manual (BWRVIP-114), RAMA Fluence Methodology Benchmark Manual (BWRVIP-115), RAMA Fluence Methodology - Susquehanna Unit 2 Surveillance Capsule Fluence Evaluation for Cycles 1-5 (BWRVIP-117), RAMA Fluence Methodology Procedures Manual (BWRVIP-121), and Hope Creek Flux Wire Dosimeter Activation

4.8.41 BFN FSAR Table 4.2-2, Reactor Vessel Data

4.8.42 BFN FSAR Table 1.7-1, Sheet 3, Comparison of Nuclear System Design Characteristics

4.8.43 BFN FSAR Table 3.3-1, Reactor Vessel Internals, Design Data

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Appendix A - Final Safety Analysis Report Supplement Table of Contents

Appendix A - Final Safety Analysis Report Supplement

A.1.0 Introduction

The application for a renewed operating license is required by 10 CFR 54.21(d) to include a FSAR Supplement. This appendix, which includes the following sections, comprises the FSAR supplement:

- Section A.1.1 contains a listing of the aging management programs that correspond to NUREG-2191 Chapter XI programs, including the status of the programs at the time the Subsequent License Renewal Application was submitted.
- Section A.1.2 contains a listing of aging management programs that correspond to NUREG-2191 Chapter X programs associated with Time-Limited Aging Analyses, including the status of the programs at the time the Subsequent License Renewal Application was submitted.
- Section A.1.3 contains a listing of the Time-Limited Aging Analyses summaries (TLAAs).
- Section A.1.4 contains a discussion of the Quality Assurance Program and Administrative Controls.
- Section A.1.5 contains a discussion of Operating Experience.
- Section A.2 contains a summarized description of the aging management programs.
- Section A.2.1 contains a summarized description of the NUREG-2191 Chapter XI programs for managing the effects of aging.
- Section A.3 contains a summarized description of the NUREG-2191 Chapter X programs that support the TLAAs.
- Section A.4 contains a summarized description of the TLAAs applicable to the Subsequent period of extended operation.
- Section A.5 contains the Subsequent License Renewal Commitment List.

The integrated plant assessment for license renewal identified new and existing aging management programs necessary to provide reasonable assurance that systems, structures, and components within the scope of license renewal will continue to perform their intended functions consistent with the Current Licensing Basis (CLB) for the period of extended operation. The subsequent period of extended operation is defined as 20 years from the unit's current operating license expiration date.

A.1.1 NUREG-2191 Chapter XI Aging Management Programs

The NUREG-2191 Chapter XI Aging Management Programs (AMPs) are described in the following sections. The AMPs are either consistent with generally accepted industry methods as discussed in NUREG-2191 or require enhancements.

The following list reflects the status of these programs at the time of the Subsequent License Renewal Application (SLRA) submittal. Commitments for program additions and enhancements are identified in the Section A.5, Subsequent License Renewal Commitment List.

1. ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section A.2.1.1) [Existing]
2. Water Chemistry (Section A.2.1.2) [Existing]
3. Reactor Head Closure Stud Bolting (Section A.2.1.3) [Existing - Requires Enhancement]

4. BWR Vessel ID Attachment Welds (Section A.2.1.4) [Existing]
5. BWR Stress Corrosion Cracking (Section A.2.1.5) [Existing - Requires Enhancement]
6. BWR Penetrations (Section A.2.1.6) [Existing - Requires Enhancement]
7. BWR Vessel Internals (Section A.2.1.7) [Existing - Requires Enhancement]
8. Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (Section A.2.1.8) [New]
9. Flow-Accelerated Corrosion (Section A.2.1.9) [Existing - Requires Enhancement]
10. Bolting Integrity (Section A.2.1.10) [Existing - Requires Enhancement]
11. Open-Cycle Cooling Water System (Section A.2.1.11) [Existing - Requires Enhancement]
12. Closed Treated Water Systems (Section A.2.1.12) [Existing - Requires Enhancement]
13. Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (Section A.2.1.13) [Existing - Requires Enhancement]
14. Compressed Air Monitoring (Section A.2.1.14) [Existing - Requires Enhancement]
15. Fire Protection (Section A.2.1.15) [Existing - Requires Enhancement]
16. Fire Water System (Section A.2.1.16) [Existing - Requires Enhancement]
17. Outdoor and Large Atmospheric Metallic Storage Tanks (Section A.2.1.17) [Existing - Requires Enhancement]
18. Fuel Oil Chemistry (Section A.2.1.18) [Existing - Requires Enhancement]
19. Reactor Vessel Material Surveillance (Section A.2.1.19) [Existing - Requires Enhancement]
20. One-Time Inspection (Section A.2.1.20) [New]
21. Selective Leaching (Section A.2.1.21) [New]
22. ASME Code Class 1 Small-Bore Piping (Section A.2.1.22) [New]
23. External Surfaces Monitoring of Mechanical Components (Section A.2.1.23) [New]
24. Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section A.2.1.24) [New]
25. Lubricating Oil Analysis (Section A.2.1.25) [New]
26. Monitoring of Neutron-Absorbing Materials Other Than Boraflex (Section A.2.1.26) [New]
27. Buried and Underground Piping and Tanks (Section A.2.1.27) [Existing - Requires Enhancement]
28. Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (Section A.2.1.28) [New]
29. ASME Section XI, Subsection IWE (Section A.2.1.29) [Existing - Requires Enhancement]
30. ASME Section XI, Subsection IWF (Section A.2.1.30) [Existing - Requires Enhancement]
31. 10 CFR Part 50, Appendix J (Section A.2.1.31) [Existing]
32. Masonry Walls (Section A.2.1.32) [Existing - Requires Enhancement]
33. Structures Monitoring (Section A.2.1.33) [Existing - Requires Enhancement]
34. Inspection of Water-Control Structures Associated with Nuclear Power Plants (Section A.2.1.34) [Existing - Requires Enhancement]

35. Protective Coating Monitoring and Maintenance (Section A.2.1.35) [New]
36. Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.1.36) [Existing - Requires Enhancement]
37. Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (Section A.2.1.37) [Existing - Requires Enhancement]
38. Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.1.38) [Existing - Requires Enhancement]
39. Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.1.39) [New]
40. Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.1.40) [New]
41. Metal Enclosed Bus (Section A.2.1.41) [Existing - Requires Enhancement]
42. Fuse Holders (Section A.2.1.42) [New]
43. Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section A.2.1.43) [New]

A.1.2 NUREG-2191 Chapter X Aging Management Programs

The NUREG-2191 Chapter X Aging Management Programs (AMP) associated with Time-Limited Aging Analyses are described in the following sections. The AMPs are either consistent with generally accepted industry methods as discussed in NUREG-2191 Chapter X or require enhancements. The following list reflects the status of these programs at the time of the Subsequent License Renewal Application (SLRA) submittal. Commitments for program additions and enhancements are identified in Section A.5, Subsequent License Renewal Commitment List.

1. Fatigue Monitoring (Section A.3.1.1) [Existing - Requires Enhancement]
2. Neutron Fluence Monitoring (Section A.3.1.2) [New]
3. Environmental Qualification of Electric Equipment (Section A.3.1.3) [Existing - Requires Enhancement]

A.1.3 Time-Limited Aging Analyses

Summaries of the Time-Limited Aging Analyses applicable to the subsequent period of extended operation are included in the following sections:

1. Identification and Evaluation of Time-Limited Aging Analyses (Section A.4.1)
2. Reactor Vessel and Internals Neutron Embrittlement Analyses (Section A.4.2)
3. Reactor Vessel and Internals Neutron Fluence Analyses (Section A.4.2.1)
4. Reactor Vessel Neutron Fluence Analyses (Section A.4.2.1.1)
5. Reactor Vessel Internals Neutron Fluence Analyses (Section A.4.2.1.2)
6. Reactor Vessel Upper-Shelf Energy (USE) Analyses (Section A.4.2.2)

7. Reactor Vessel Adjusted Reference Temperature (ART) Analyses (Section A.4.2.3)
8. Reactor Vessel Pressure-Temperature (P-T) Limits (Section A.4.2.4)
9. Reactor Vessel Circumferential Weld Failure Probability Analyses (Section A.4.2.5)
10. Reactor Vessel Axial Weld Failure Probability Analyses (Section A.4.2.6)
11. Reactor Vessel Reflood Thermal Shock Analysis (Section A.4.2.7)
12. Core Shroud Reflood Thermal Shock Analysis (Section A.4.2.8)
13. Core Plate Hold-Down Bolt Loss of Preload Analysis (Section A.4.2.9)
14. Jet Pump Slip Joint Repair Clamp Loss of Preload Analysis (Section A.4.2.10)
15. Jet Pump Auxiliary Spring Wedge Assembly Loss of Preload Analysis (Section A.4.2.11)
16. Jet Pump Riser Repair Clamp Loss of Preload Analysis (Section A.4.2.12)
17. Replacement Core Support Plate Plug Extended Life Irradiation - Enhanced Stress Relaxation Analysis (Section A.4.2.13)
18. Irradiation Assisted Stress Corrosion Cracking (IASCC) of Reactor Vessel Internals (Section A.4.2.14)
19. Core Spray Replacement Piping Bolting Loss of Preload Evaluation (Section A.4.2.15)
20. Core Spray Sparger Repair Clamp Loss of Preload Evaluation (Section A.4.2.16)
21. Access Hole Cover Repair Loss of Preload Evaluation (Section A.4.2.17)
22. Jet Pump Hold-Down Beam Assembly Loss of Preload Analysis (Section A.4.2.18)
23. Jet Pump Sensing Line Clamps Loss of Preload Analysis (Section A.4.2.19)
24. Metal Fatigue Analyses (Section A.4.3)
25. Transient Cycles and Cumulative Usage Projections for 80 Years (Section A.4.3.1)
26. Metal Fatigue of Class 1 Fatigue Analyses (Section A.4.3.2)
27. Class 1 Fatigue Waivers (Section A.4.3.3)
28. Metal Fatigue of Non-Class 1 Components (Section A.4.3.4)
29. Environmental Fatigue Analyses for Reactor Vessel and Class 1 Piping (Section A.4.3.5)
30. Replacement Steam Dryer Stress Report and Fatigue Evaluation (Section A.4.3.6)
31. Emergency Equipment Cooling Water Weld Flaws Evaluation (Section A.4.3.7)
32. Core Shroud Support Fatigue Analysis (Section A.4.3.8)
33. BFN Unit 3 Core Spray T-Box Repair Fatigue Evaluation (Section A.4.3.9)
34. BFN Unit 3 Core Spray Lower Line Section Replacement Fatigue Evaluation (Section A.4.3.10)
35. Jet Pump to Core Shroud Support Plate Fatigue Evaluation (Section A.4.3.11)
36. Environmental Qualification of Electric Equipment (Section A.4.4)
37. Environmental Qualification of Electric Equipment (Section A.4.4.1)
38. Concrete Containment Tendon Prestress Analysis (Section A.4.5)
39. Primary Containment Fatigue Analyses (Section A.4.6)
40. Suppression Chambers, Vents and Downcomers Fatigue Analyses (Section A.4.6.1)

41. Torus Attached Piping and Safety Relief Valve Discharge Lines Fatigue Analyses (Section A.4.6.2)
42. Containment Vent Lines and Process Penetration Bellows Fatigue Analyses (Section A.4.6.3)
43. Other Plant-Specific Time-Limited Aging Analyses (Section A.4.7)
44. Reactor Building Crane Cyclic Loading Analysis (Section A.4.7.1)
45. Radiation Degradation of Drywell Expansion Gap Foam Analysis (Section A.4.7.2)
46. BFN Unit 2 Reactor Vessel Axial Weld Flaw (Section A.4.7.3)

A.1.4 Quality Assurance Program and Administrative Controls

The TVA Nuclear Quality Assurance Plan (NQAP) implements the requirements of 10 CFR 50, Appendix B and is consistent with the summary in Appendix A.2, “Quality Assurance For Aging Management Programs (Branch Technical Position IQMB-1)” of NUREG-2192. The scope of the TVA NQAP includes all systems, structures, and components (SSCs) that are safety-related and also includes quality-related programs and features that are important to continued reliable operation of TVA's nuclear facilities. The TVA NQAP includes the elements of corrective action, confirmation process, and administrative controls. The TVA NQAP elements of corrective action, confirmation process, and administrative controls will be applied to all Aging Management Programs (AMPs) credited for subsequent license renewal, including programs for safety-related and nonsafety-related structures, systems, and components. This is consistent with the approach applied for initial license renewal AMPs. In many cases, existing activities were found adequate for managing aging effects during the subsequent period of extended operation.

A.1.5 Operating Experience

Operating experience (OE) from plant-specific and industry sources is captured and systematically reviewed on an ongoing basis in accordance with the quality assurance program, which meets the requirements of 10 CFR Part 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 OE program interfaces with and relies on active participation in the Institute of Nuclear Power Operations OE program, as endorsed by the NRC. Relevant research and development is also reviewed. In accordance with these programs, all incoming operating experience items are screened to determine whether they may involve age-related degradation or aging management impacts. 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. TVA will enhance implementing procedures such that training on age-related degradation and aging management will be 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 operating experience. Plant-specific operating experience associated with aging management and age-related degradation is reported to the industry in accordance with guidelines established in the OE program.

TVA will perform an evaluation of operating experience at extended power uprate (EPU) levels prior to the subsequent period of extended operation to ensure that operating experience at EPU levels is properly addressed by the aging management programs. The evaluation will include BFN and other BWR plants operating at EPU levels. This evaluation will be completed no later than six months prior to entering the subsequent period extended operation.

A.2.0 Aging Management Programs

A.2.1 NUREG-2191 Chapter XI Aging Management Programs

This section provides summaries of the NUREG-2191 programs credited for managing the effects of aging.

A.2.1.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

The BFN ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection aging management program is an existing program that is part of the BFN ASME Section XI Inservice Inspection program and is also supplemented by implementing the guidelines of the BWRVIP program documents. The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program provides for condition monitoring of ASME Code Class 1, 2, and 3 pressure-retaining components and their integral attachments.

The BFN ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program manages the aging effects of loss of material, cracking, and reduction in fracture toughness. The BFN ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program consists of periodic volumetric, surface, and/or visual examination of ASME Class 1, 2, and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting for assessment, signs of degradation, and corrective actions. The ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection program is in accordance with the ASME Code Section XI edition and addenda approved in accordance with provisions of 10 CFR 50.55a during the subsequent period of extended operation.

A.2.1.2 Water Chemistry

The BFN Water Chemistry aging management program is an existing program that mitigate the loss of material due to corrosion, cracking due to stress corrosion cracking (SCC) and related mechanisms, and reduction of heat transfer due to fouling in components exposed to a reactor coolant, steam, or treated water environment. The program includes periodic monitoring and trending of the treated water and control of known detrimental contaminants such as conductivity, chloride, and sulfate concentrations within the guidelines of the Boiling Water Reactor Vessel and Internals Project BWRVIP-190, BWR Vessel and Internals Project: BWR Water Chemistry Guidelines, Revision 1, to minimize loss of material or cracking.

The BFN Water Chemistry program consists of monitoring and controlling the chemical environments of those systems that are exposed to reactor water, steam, condensate, feedwater, control rod drive water, demineralized water, torus water, and spent fuel pool water, such that aging effects of system components are minimized in accordance with BWRVIP-190, Revision 1. Sampling frequencies, action limits for each control parameter, and corrective actions are defined in specific procedures. Conditions that do not meet acceptance criteria are evaluated in accordance with the Corrective Action Program.

Major component types managed by this program include the reactor vessel, reactor internals, piping, piping elements, heat exchangers, and tanks. Reactor water, condensate, control rod drive water, feedwater, demineralized water storage tank water, torus water, spent fuel pool water, and condensate storage tank water are classified as treated water for aging management.

The BFN Water Chemistry program includes specifications for chemical species, sampling and analysis frequencies, and corrective actions for control of the plant/system water chemistry.

The BFN Water Chemistry program contains specific actions required to be taken when measured water chemistry parameters are outside the specified range, corrective actions to take to bring the parameter back within the acceptable range (or to change the operational mode of the plant) within the time period specified in the EPRI water chemistry guidelines. Whenever corrective actions are taken to address an abnormal chemistry condition, the BFN Water Chemistry program requires increased sampling or other appropriate actions to verify that the corrective actions were effective in returning the concentrations of contaminants, such as chlorides, fluorides, sulfates, and dissolved oxygen, to within the acceptable ranges.

A.2.1.3 Reactor Head Closure Stud Bolting

The BFN Reactor Head Closure Stud Bolting aging management program is an existing condition monitoring and preventive program that manages reactor head closure studs, flange threads, and associated nuts, washers, and bushings, for cracking and loss of material. The program is implemented through station procedures based on the examination requirements specified in ASME Code, Section XI, Subsection IWB, Table IWB-2500-1 and preventive measures to mitigate cracking as delineated in NRC Regulatory Guide 1.65, Materials and Inspection for Reactor Vessel Closure Studs, Revision 1, with the exception that existing stud bolting components have a measured yield strength greater than or equal to 150 ksi and an ultimate tensile stress greater than or equal to 170 ksi.

The Reactor Head Closure Stud Bolting aging management program will be enhanced as follows:

1. Ensure the use of molybdenum disulfide (MoS_2) as a lubricant for reactor vessel closure studs is prohibited.
2. Revise implementing procedures to require that future replacement studs not be metal plated, the studs will use a bolting material for closure studs that has an actual measured yield strength less than 150 kilo-pounds per square inch (ksi) [1,034 megapascals (MPa)], and the replacement studs will have a manganese phosphate or other acceptable surface treatment.
3. Ensure repair and replacement be performed in accordance with the requirements of IWA-4000 and the material and inspection guidance of Regulatory Guide 1.65, Revision 1. The actual measured maximum yield strength of replacement material will be limited to 150 ksi as recommended in Regulatory Guide 1.65, Revision 1.

These enhancements will be implemented no later than six months prior to the subsequent period of extended operation.

A.2.1.4 BWR Vessel ID Attachment Welds

The BFN BWR Vessel ID Attachment Welds aging management program is an existing condition monitoring program that manages cracking of the reactor vessel interior attachment welds. This program relies on visual examinations to detect cracking. The examination scope, frequencies, and methods are in accordance with the guidance provided by BWRVIP-48 Revision 2, “BWR Vessel and Internals Project, Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines,” and are substituted for the requirements of ASME Code, Section XI, Table IWB-2500-1, Examination Category B-N-2. The scope of the examinations is expanded when flaws are detected. Any indications are evaluated in accordance with the guidance in BWRVIP-48 Revision 2. Crack growth evaluations follow the guidance in BWRVIP-14-A, “BWR Vessel and Internals Project, Evaluation of Crack Growth in BWR Stainless Steel RPV Internals,” BWRVIP-59-A, “BWR Vessel and Internals Project, Evaluation of Crack Growth in BWR Nickel-Base Austenitic Alloys in RPV Internals,” or BWRVIP-60-A, “BWR Vessel and Internals Project, Evaluation of Crack Growth in BWR Low Alloy Steel RPV Internals,” as appropriate. The acceptance criteria are in BWRVIP-48 Revision 2 and ASME Code, Section XI, Subarticle IWB-3520. Repair and replacement activities are conducted in accordance with BWRVIP-52-A.

A.2.1.5 BWR Stress Corrosion Cracking

The BFN BWR Stress Corrosion Cracking aging management program is an existing condition monitoring and mitigative program that manages intergranular stress corrosion cracking (IGSCC) for all BWR piping and piping welds made of austenitic stainless steel and nickel-based alloy that are 4 inches or larger in diameter containing reactor coolant at a temperature above 200 degrees F during power operation, regardless of Code classification. The program also applies to pump casings, valve bodies, and reactor vessel attachments.

The program includes periodic volumetric examinations to detect and manage IGSCC in accordance with NRC Generic Letter 88-01. The extent and schedule of inspection described in Generic Letter 88-01 are modified in accordance with the inspection guidance in staff-approved BWRVIP-75-A. The program includes the staff approved positions delineated in NUREG-0313, Revision 2, and Generic Letter 88-01 and its Supplement 1 regarding selection of IGSCC resistant materials, solution heat treatment and stress improvement processes, water chemistry, weld overlay reinforcement, partial replacement, clamping devices, crack characterization and repair criteria, inspection methods and personnel, inspection schedules, sample expansion, leakage detection, and reporting.

The BWR Stress Corrosion Cracking aging management program will be enhanced as follows:

1. Revise implementing procedures to explicitly state that the approved guidelines contained in BWRVIP-14-A, BWRVIP-59-A, BWRVIP-60-A, and BWRVIP-62 Revision 2 are used for evaluating crack growth in stainless, nickel alloys, and low-alloy steels.
2. Revise implementing procedures to explicitly state that, in accordance with NRC Generic Letter 88-01, repair of an IGSCC flaw, or an evaluation performed to accept a flaw must be approved by the NRC before resuming power operation.
3. Revise implementing procedures to explicitly state that corrective actions for stress corrosion cracking are performed in accordance with the guidance for replacement, weld overlay repair, and stress improvement provided in industry documents, including NRC Generic Letter 88-01, NUREG-0313 Revision 2, ASME Code, Section XI, Subsection IWA-4000, and approved Code Cases.

These enhancements will be implemented no later than six months prior to the subsequent period of extended operation.

A.2.1.6 BWR Penetrations

The BFN BWR Penetrations aging management program is an existing condition monitoring program that manages the effects of cracking due to cyclic loading, stress corrosion cracking, or intergranular stress corrosion cracking of BWR instrumentation penetrations, CRD housing and incore-monitoring housing penetrations, and the SLC/Core Plate ΔP nozzle exposed to reactor coolant by performing inspections and flaw evaluations. The inspection and flaw evaluation recommendations of BWRVIP-47-A, “BWR Lower Plenum Inspection and Flaw Evaluation Guidelines,” are used in lieu of the requirements of ASME Code, Section XI, as a result of an NRC approved request for alternative implementation of the BWRVIP Program for Vessel Internals. The inspection and flaw evaluation recommendations of BWRVIP-49-A, “Instrument Penetration Inspection and Flaw Evaluation Guidelines,” and BWRVIP-27-A, “BWR Standby Liquid Control System/Core Plate ΔP Inspection and Flaw Evaluation Guidelines,” are used to augment the examination requirements of ASME Code, Section XI. The examination categories include volumetric, surface, and visual examination methods. All other requirements of ASME Code, Section XI for which an alternative implementation has not been specifically requested remain applicable, including third party review by the Authorized Nuclear Inservice Inspector. Any ASME Code, Section XI, reactor vessel internals components that are not included in this request for alternative implementation will continue to be inspected in accordance with the ASME Code, Section XI requirements. The inspection and evaluation guidelines addressed in the relevant BWRVIP reports will be implemented for the non-ASME Code, Section XI, reactor vessel internals components at BFN. Required repairs or replacements of components within the jurisdiction of ASME Code, Section XI, are implemented in accordance with ASME Code, Section XI, Article IWA-4000 and consistent with the recommendations of BWRVIP-53-A, “Standby Liquid Control Line Repair Design Criteria,” BWRVIP-55-A, “Lower Plenum Repair Design Criteria,” BWRVIP-57 Revision 1, “Instrument Penetration Repair Design Criteria,” and BWRVIP-58-A, “CRD Internal Access Weld Repair.” The BWR Penetrations aging management program also incorporates the water chemistry recommendations described in the BFN Water Chemistry program (A.2.1.2).

The BWR Penetrations aging management program will be enhanced as follows:

1. Revise implementing procedures to explicitly state that the approved guidelines contained in BWRVIP-53-A, BWRVIP-55-A, BWRVIP-57 Revision 1, and BWRVIP-58-A are used as a source of repair design criteria for reactor vessel internals components, as applicable.

This enhancement will be implemented no later than six months prior to the subsequent period of extended operation.

A.2.1.7 BWR Vessel Internals

The BFN BWR Vessel Internals aging management program is an existing condition monitoring and mitigative program that includes inspections and flaw evaluations in conformance with the guidelines of applicable staff approved Boiling Water Reactors Vessel and Internals Project (BWRVIP) documents and provides reasonable assurance of the long-term integrity and safe operation of BWR vessel internal components that are fabricated of nickel alloy and stainless steel (including cast stainless steel, and associated welds).

The BWR Vessel Internals program manages the effects of cracking due to stress corrosion cracking (SCC), intergranular stress corrosion cracking (IGSCC), or irradiation assisted stress corrosion cracking (IASCC), cracking due to cyclic loading (including flow-induced vibration), loss of material due to wear, loss of fracture toughness due to neutron or thermal embrittlement, and loss of preload due to thermal or irradiation-enhanced stress relaxation.

The program performs inspections for cracking and loss of material in accordance with the guidelines of applicable staff approved BWRVIP documents and the requirements of ASME Code, Section XI, Table IWB 2500-1. However, all three BFN units utilize an NRC Approved Request for Alternative Implementation of the BWRVIP Program for Vessel Internals in lieu of the requirements of ASME Code, Section XI, due to the fact that the NRC found that the TVA proposed alternative provided an acceptable level of quality and safety for the vessel internals components because the proposed alternate provides for equivalent or superior flaw detection and characterization with an examination frequency that is equivalent or more frequent than the ASME Code requirements. The Alternative Implementation of the BWRVIP Program for Vessel Internals includes examination methods, examination volume, frequency, training, successive and additional examinations, flaw evaluations, and reporting.

The impact of loss of fracture toughness on component integrity is indirectly managed by using visual or volumetric examination techniques to monitor for cracking of the components. This program also manages loss of preload for jet pump assembly hold-down beam bolts by performing visual inspections or stress analyses for adequate structural integrity. Manufacturer supplied guidance is used for inspections of the replacement steam dryers.

This program performs evaluations to determine whether supplemental inspections in addition to the existing BWRVIP examination guidelines are necessary to adequately manage loss of fracture toughness due to thermal or neutron embrittlement and cracking due to IASCC for the subsequent period of extended operation. If the evaluations determine that supplemental inspections are necessary for certain components based on neutron fluence, cracking susceptibility and fracture toughness, the program conducts the supplemental inspections for adequate aging management.

The program is updated periodically as required by 10 CFR 50.55a and the BWRVIP.

Evaluations of reactor vessel internal component determined that supplemental inspections in addition to the existing BWRVIP examination guidelines are not necessary to manage loss of fracture toughness due to thermal aging embrittlement or neutron irradiation embrittlement and cracking due to IASCC during the subsequent period of extended operation. This determination is based on neutron fluence, cracking susceptibility, fracture toughness, and consequences of cracking or failure of the reactor vessel internal components.

The BWR Vessel Internals aging management program will be enhanced as follows:

1. Revise implementing procedures to explicitly state that the approved guidelines contained in BWRVIP-14-A, BWRVIP-59-A, BWRVIP-60-A, and BWRVIP-62 Revision 2 are used as a source of repair design criteria for reactor vessel internals components, as applicable.
2. Revise implementing procedures to implement BWRVIP-315-A and subsequent revisions approved by the NRC for BFN to use during the subsequent period of extended operation.
3. Revise implementing procedures to incorporate the requirement for justifying the frequency of subsequent inspections based on appropriate fracture toughness properties if component cracking is detected during inspection.
4. Revise implementing procedures to explicitly state that the approved guidelines contained in BWRVIP-14-A, BWRVIP-59-A, BWRVIP-60-A, BWRVIP-80-A and BWRVIP-99-A are used,

as applicable, as a source of guidelines for evaluating crack growth in stainless steels, nickel alloys, and low-alloy steels, and that BWRVIP-100 Revision 2 is used as a source for flaw evaluation methodologies and fracture toughness data for SS core shroud exposed to neutron irradiation.

5. Revise implementing procedures to explicitly state that the guidelines contained in BWRVIP-97 Revision 1 are used as a source of guidelines for performing weld repairs to irradiated vessel internal components.
6. Revise implementing procedures to explicitly state that the guidelines in BWRVIP-84, Revision 3 (or a later revision if approved and issued) are used to provide guidance on procurement, design and welding requirements, fabrication limitations, and numerous other issues (including maintaining operating tensile stresses below a threshold limit that mitigates IGSCC) for the four specific material types used for in-vessel repairs: 300 Series austenitic stainless steel, Alloy X-750, Type XM-19 and Alloy 718. The resulting specification is then used for designing repairs to the following internal components that fall within the scope of the BWRVIP program: core shroud, shroud support, core spray, top guide, core plate, standby liquid control line, jet pumps, control rod drive components, instrument penetrations, and vessel brackets.

These enhancements will be implemented no later than six months prior to the subsequent period of extended operation.

A.2.1.8 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)

The BFN Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) aging management program is a new condition monitoring program that will provide assurance that RCPB CASS components (i.e., pump casings) with the potential for significant thermal aging embrittlement meet their intended functions. The ASME Code Class 1 CASS components are maintained by inspecting and evaluating the extent of thermal aging embrittlement in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section XI. The BFN ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (A.2.1.1) is augmented by the implementation of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program which will monitor the aging effect of loss of fracture toughness due to thermal aging embrittlement of ASME Code Class 1 CASS components with service conditions above 250°C (482°F).

BFN does not have any Class 1 piping or fittings fabricated from CASS that are susceptible to thermal aging embrittlement of cast austenitic stainless steel. The main steam line flow restricting venturis are fabricated from CASS. However, these components have been evaluated and, based on material and environmental characteristics, are not susceptible to thermal aging embrittlement. Therefore, these venturis are not within the Thermal Aging Embrittlement of CASS program. The Class 1 reactor recirculation pump casings are fabricated from CASS and are within the scope of the Thermal Aging Embrittlement of CASS program.

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program will include a screening methodology to determine components for which thermal aging embrittlement is potentially significant based on casting method, molybdenum content, and percent ferrite. Components with the potential for significant thermal aging embrittlement will be managed through qualified visual inspections, such as enhanced visual examination or qualified ultrasonic testing (UT) methodology.

Inspections are not required for components for which thermal aging embrittlement is not significant. In addition, screening for ASME Code Class 1 CASS valve bodies for significance of thermal aging embrittlement is not required, because the existing ASME Section XI inspection requirements are adequate for managing the aging effects of Class 1 valve bodies. Reactor vessel internal components fabricated from CASS are not within the scope of this aging management program and are managed by the BWR Vessel Internals program (A.2.1.7).

This new aging management program will be implemented no later than six months prior to the subsequent period of extended operation.

A.2.1.9 Flow-Accelerated Corrosion

The BFN Flow-Accelerated Corrosion aging management program is an existing condition monitoring program that manages wall thinning caused by flow-accelerated corrosion (FAC) in steel piping and piping components exposed to reactor coolant, steam, and treated water environments. The program is based on commitments made in response to NRC Generic Letter 89-08, “Erosion/Corrosion Induced Pipe Wall Thinning,” and relies on implementation of the Electric Power Research Institute (EPRI) guidelines in NSAC-202L for an effective FAC program.

CHECWORKS^{TM} is used to predict component wear rates and remaining service life in the systems susceptible to FAC which provides reasonable assurance that structural integrity will be maintained between inspections. The model is revised if any changes in operating conditions or other factors that affect FAC (e.g., plant chemistry, power uprate) have occurred since the CHECWORKS^{TM} model was last updated. Changes may also result from plant modifications that effect FAC behavior such as material changes, the addition of piping systems, piping system configuration changes, and the addition or replacement of in-line components. The CHECWORKS^{TM} model is also refined by importing actual volumetric inspection data thickness measurements and re-running the wear rate analysis. This improves the predictive capability of the model to ensure that intended functions are maintained. Additionally, the program utilizes industry operating experience, plant experience, and engineering judgment of plant engineers to determine inspection locations.

The program also manages wall thinning caused by erosion in metallic heat exchanger components, piping and piping components exposed to reactor coolant, raw water, steam, and treated water in situations where periodic monitoring is used in lieu of eliminating the cause of various erosion mechanisms.

The program includes: (a) identifying all susceptible piping systems and components; (b) developing FAC predictive models to reflect component geometries, materials, and operating parameters; (c) performing analysis of FAC models and, with consideration of operating experience, selecting a sample of components for inspections; (d) inspecting components; (e) evaluating and trending 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.

FAC inspections and inspections performed for wall thinning caused by mechanisms other than FAC that do not meet acceptance criteria are evaluated in accordance with the Corrective Action Program.

The Flow-Accelerated Corrosion aging management program will be enhanced as follows:

1. Ensure the management of wall thinning in screened-in components within the scope of SLR that are subject to erosion mechanisms in situations where periodic monitoring is used in lieu of elimination of the cause of various erosion mechanisms.
2. Ensure opportunistic visual inspections of up-stream and down-stream piping and components are performed during periodic pump and valve maintenance or during pipe replacements to assess internal surface conditions.
3. Reassess piping systems that have been excluded from wall thickness monitoring due to operation less than 2 percent of plant operating time (as allowed by NSAC-202L) to ensure the exclusion remains valid and applicable for operation beyond 60 years. If actual wall thickness information is not available for use in this reassessment, a representative sampling approach can be used.For erosion mechanisms, ensure the identification of susceptible locations is based on the extent-of-condition reviews from corrective actions in response to plant-specific and industry OE. A combination of operating experience, results of prior inspections, engineering judgment and analysis will be used to select inspection locations.
4. For erosion mechanisms, ensure:
   - Trending of wall thickness measurements to adjust the monitoring frequency and to predict the remaining service life of the component for scheduling repairs or replacements is required;
   - Inspection results are evaluated to determine if assumptions in the extent-of-condition review remain valid;
   - If degradation is associated with infrequent operational alignments, such as surveillances or pump starts/stops, then trending activities consider the number or duration of these occurrences; and
   - Periodic wall thickness measurements of replacement components may be required and should continue until the effectiveness of corrective actions has been confirmed.
5. For erosion mechanisms, ensure the effectiveness of long-term corrective actions is verified when long term corrective actions include elimination of the cause by adjusting operating parameters and/or changing components' geometric designs. Ensure periodic monitoring activities continue for any component replaced, due to erosion, with an alternate material, since a material that is completely resistant to erosion mechanisms is not available.

These enhancements will be implemented no later than six months prior to the subsequent period of extended operation. The reassessment of exclusions will be completed no later than six months prior to the subsequent period of extended operation.

A.2.1.10 Bolting Integrity

The BFN Bolting Integrity aging management program is an existing condition monitoring program that manages aging of closure bolting for pressure-retaining components. The program includes periodic visual inspection of closure bolting for indications of loss of preload, cracking, and loss of material due to general, pitting, and crevice corrosion, microbiologically influenced corrosion (MIC), and wear as evidenced by leakage. The program also includes periodic sample inspections on closure bolting that is submerged or where the piping systems contains air or gas for which leakage is difficult to detect. The program also includes sampling-based volumetric examinations of high-strength closure bolting to detect indications of cracking.

Preventive measures to preclude or minimize loss of preload and cracking include material selection, thread lubricant control, assembly and torque requirements, and repair and replacement requirements. This program relies on recommendations for a comprehensive bolting integrity program, as delineated in NUREG-1339, dated June 1990, and EPRI NP-5769, dated April 1988. The program also relies on industry recommendations for comprehensive bolting maintenance, as delineated in the EPRI TR-1015336, dated December 2007, and EPRI TR-1015337, dated December 2007.

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (A.2.1.1) includes inspection of safety-related closure bolting on pressure-retaining components, and supplements this program. The Bolting Integrity aging management 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 Section XI, Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1. Inspection activities for bolting in a buried environment or underground with restricted access are performed in conjunction with buried piping and component inspections performed as part of the Buried and Underground Piping and Tanks program (A.2.1.27).

The Reactor Head Closure Stud Bolting program (A.2.1.3) manages the aging effects of the bolting components for the reactor vessel closure head. The ASME Section XI, Subsection IWE program (A.2.1.29), ASME Section XI, Subsection IWF program (A.2.1.30); Structures Monitoring program (A.2.1.33); Inspection of Water-Control Structures Associated with Nuclear Power Plants program (A.2.1.34); and Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program (A.2.1.13); manage the aging effects of safety-related and nonsafety-related structural bolting. The External Surfaces Monitoring of Mechanical Components program (A.2.1.23) manages the aging effects of safety-related and nonsafety-related bolting associated with ductwork for heating, ventilation, and air conditioning systems.

The Bolting Integrity aging management program will be enhanced as follows:

1. Ensure the maximum yield strength of replacement or newly procured pressure-retaining bolting material is limited to an actual yield strength less than 150 ksi (1,034 MPa) to preclude or minimize loss of preload and cracking.
2. Revise implementing procedures to require periodic inspections of ASME Code Class 1, 2, and 3, and non-ASME Code class bolted joints for signs of leakage at least once per refueling cycle.
3. Revise implementing procedures to require sampling-based inspections to include a representative sample of 20 percent of the population of bolt heads and threads (defined as bolts with the same material and environment combination) or a maximum of 25 bolts per population at each unit per 10-year interval during the subsequent period of extended operation. Opportunistic inspections during maintenance activities may be credited during the same 10-year interval.
4. Revise implementing procedures to require, for all closure bolting greater than 2 inches in diameter (regardless of code classification) with actual yield strength greater than or equal to 150 ksi and closure bolting for which yield strength is unknown, performance of volumetric examination in accordance with ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, is performed (i.e., acceptance standards, extent, and frequency of examination).

5. Revise implementing procedures to establish the alternate methods of inspections of closure bolting in locations that preclude detection of joint leakage, as follows:
   - For systems containing air/gas, alternative inspections will include one or more of the following: (a) inspection consistent with that of submerged bolting; (b) visual inspection for discoloration when leakage from inside the piping system would discolor the external surfaces of the component; (c) monitoring and trending of pressure decay when the bolted connection is located within an isolated boundary; (d) soap bubble testing on the external mating surface of the bolted component; or (e) thermography, when the temperature of the process fluid is higher than ambient conditions around the component.
   - Alternative inspection of carbon steel submerged closure bolting on the RHRSW, HPFP and CCW pumps located at the Intake Channel will consist of visual inspections by divers and periodic vibration monitoring (measurement). Divers will inspect for degraded, visibly loose, missing, or broken bolts. Periodic (minimum semiannual) vibration monitoring of the pump/motor assembly will also be performed as an alternative inspection method. Increased vibration could be an indication of degradation of the pump casing upper flange bolted joint. Vibration readings will be trended.
   - For systems not normally pressurized, inspections for indication of leakage will be coordinated with scheduled operation of the system such as periodic surveillances. If system pressurization does not present the opportunity to perform the minimum required bolting inspections, then the visual inspections will be supplemented with torque checks to the extent that the bolting is not loose.
6. Revise implementing procedures for non-code closure bolting inspections to include methods for detecting aging effects and indications of joint leakage, as well as inspection parameters for items such as lighting, distance, and offset, which provide an adequate examination.
7. Revise implementing procedures to require, where practical, identified degradation to be projected until the next scheduled inspection. Results will be evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation. For sampling-based inspections, results will be evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation.
8. Revise implementing procedures to establish plant-specific acceptance criteria for alternative inspections or testing for submerged closure bolting or closure bolting where the piping systems contains air or gas for which leakage is difficult to detect, such as: soap bubble testing, thermography, monitoring of pressure decay, or torque checks to the extent that the bolting is not loose.
9. Revise implementing procedures to ensure that if a bolted connection for pressure-retaining components is reported to be leaking, follow-up periodic visual inspections will be conducted until the leak is corrected. If the leak rate is increasing, more frequent inspections are warranted. The effects of leakage from bolted connections that have an intended function identified in 10 CFR 54.4(a)(2) will be evaluated for its impact on components with an intended function identified in 10 CFR 54.4(a)(1) and located within the vicinity of the leaking bolted connection.
10. Revise implementing procedures to require, for sampling-based inspections, for a situation in which an acceptance criterion for allowable degradation is exceeded, and the aging effect causing the degradation for the material/environment combination is not corrected by repair or replacement, that additional inspections will be performed. The number of additional

inspections will be determined in accordance with the Corrective Action Program; however, no fewer than five additional (or 20%, whichever is less) inspections will be performed of different components having the same material/environment/aging effect combination as the component(s) that did not meet the acceptance criterion. If these subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be performed to determine the further extent of inspections. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections for all BFN units' components having the same material, environment, and aging effect combination. The additional inspections will be completed within the same interval for which the original sample-based inspections are conducted. 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.

These enhancements will be implemented no later than six months prior to the subsequent period of extended operation.

A.2.1.11 Open-Cycle Cooling Water System

The BFN Open-Cycle Cooling Water (OCCW) System aging management program is an existing condition monitoring program and includes preventive measures. The program relies, in part, on implementing portions of the recommendations for the NRC Generic Letter 89-13 and provides reasonable assurance that the effects of aging on the OCCW (or service water) system will be managed for the subsequent period of extended operation. The BFN OCCW System program is comprised of the aging management aspects of BFN's response to NRC Generic Letter 89-13 including: (a) a program of surveillance and control techniques to significantly reduce the incidence of flow blockage problems as a result of biofouling; (b) a program to verify heat transfer capabilities of RHR heat exchangers cooled by the OCCW system; and (c) a program for routine inspection and maintenance to provide reasonable assurance that loss of material, corrosion, erosion, cracking, fouling, and biofouling cannot degrade the performance of in-scope systems serviced by the OCCW system. Use of OE is part of the BFN OCCW program to provide reasonable assurance that aging effects are adequately managed.

The BFN OCCW System program includes chemical treatment that mitigates microbiologically influenced corrosion (MIC) and buildup of macroscopic biofouling debris.

The BFN OCCW System program includes performance of inspections for detection of aging effects on the internal portions of the embedded RHRSW pipes that run between the CCW Pump Pits to the EECW/RHRSW Pump Pits and the RHRSW sluice gate valves located in the CCW Pump Pits.

The BFN OCCW System program includes trending for RHR heat exchangers, that are tested for heat transfer capability, to verify adequacy of testing frequencies. For other in-scope heat exchangers, that are inspected for degradation in lieu of testing, inspection results are trended to evaluate adequacy of inspection frequencies.

The Open-Cycle Cooling Water System aging management program will be enhanced as follows:

1. Revise implementing procedures to include heat exchangers in the High Pressure Fire Protection (Diesel Driven Pump) System, the Control Air System, and the Control Rod Drive System.
2. Revise implementing procedures to include reevaluation, repair, or replacement of components that do not meet minimum wall thickness requirements. If fouling is identified, the overall effect is evaluated for reduction of heat transfer, flow blockage, loss of material, and (if applicable) chemical treatment effectiveness. For ongoing degradation mechanisms (e.g., MIC), the frequency and extent of wall thickness inspections are increased commensurate with the significance of the degradation.
3. Revise implementing procedures to include the requirement that 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 inspections are conducted for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination will be inspected, whichever is less. The additional inspections include inspections at all BFN units with the same material, environment, and aging effect combination.

These enhancements will be implemented no later than six months prior to the subsequent period of extended operation.

A.2.1.12 Closed Treated Water Systems

The BFN Closed Treated Water Systems (CTWS) aging management program is an existing program that manages the aging effects of loss of material due to corrosion and reduction of heat transfer due to fouling of the internal surfaces of piping, piping components, piping elements and heat exchanger components fabricated from any material and exposed to treated water. The program is a mitigation program that also includes condition monitoring to verify the effectiveness of the mitigation activities. The program includes: (a) water treatment, including the use of corrosion inhibitors, to modify the chemical composition of the water such that the function of the equipment is maintained and such that the effects of corrosion are minimized; (b) chemical testing of the water to demonstrate that the water treatment program maintains the water chemistry within acceptable guidelines; and (c) inspections to determine the presence or extent of degradation.

The program includes systems that contain demineralized water that is treated with corrosion inhibitors. Corrosion inhibitors are not added to the Shutdown Board Room (SDBR) (Air Conditioning) and Variable Frequency Drive (Reactor Recirculation) systems. These systems meet the industry guidance for pure water systems.

The program chemistry parameters (such as the concentration of iron, copper, silica, oxygen, and hardness, alkalinity, specific conductivity, and pH) are monitored in the BFN Chemistry Program to optimize water chemistry which prevents loss of material and cracking due to corrosion and SCC. The program uses EPRI guidelines for chemistry control of closed cooling water systems.

In the program, aging effects will be detected through water testing and periodic inspections. Water testing determines whether the water treatment program effectively maintains acceptable water chemistry. Water testing frequency is conducted in accordance with the BFN Chemistry Program.

Inspections will be conducted in accordance with applicable ASME Code requirements. If there are no ASME Code requirements, inspections will be conducted in accordance with site procedures, which will include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

The program evaluates water chemistry data against the standards contained in the selected water treatment program. These data are trended, so corrective actions are taken, based on trends in water chemistry, prior to loss of intended function. Where practical, identified degradation will be projected until the next scheduled 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.

Water chemistry concentrations that are not in accordance with the closed treated water systems contained in the BFN Chemistry Program are returned to the normal operating range within the prescribed time frame for each action level in the BFN Chemistry Program. If fouling is identified, the overall effect is evaluated for reduction of heat transfer, flow blockage, and loss of material.

The Closed Treated Water Systems aging management program will be enhanced as follows:

1. Revise implementing procedures to manage the effects of cracking due to stress corrosion cracking in closed treated water systems.
2. Revise implementing procedures to include surface or volumetric examinations. The results of these examinations will be evaluated for surface discontinuities indicative of cracking.
3. Revise implementing procedures to include inspections of Closed Treated Water Systems components for the detection of loss of material, cracking, and fouling.
4. Revise implementing procedures to include visual inspections of internal surfaces that are conducted whenever the system boundary is opened. At a minimum, in each 10-year period during the subsequent period of extended operation, a representative sample of 20 percent of the population (defined as components having the same material, water treatment program, and aging effect combination) or a maximum of 25 components per population at each unit will be inspected using techniques capable of detecting loss of material, cracking, and fouling, as appropriate. The 20 percent minimum is surface area inspected unless the component is measured in linear feet, such as piping. In that case, any combination of 1-foot length sections and components can be used to meet the recommended extent of 25 inspections.
5. Revise implementing procedures to include expansion of the sample population if degradation is identified in the initial population in order to determine the extent of the condition.
6. Revise implementing procedures to credit ongoing opportunistic visual inspections towards the representative samples for the loss of material and fouling; however, surface or volumetric examinations will be used to detect cracking. These inspections focus on the components most susceptible to aging due to time in service and severity of operating conditions, including locations where local conditions may be significantly more severe than those in the bulk water (e.g., heat exchanger tube surfaces).

7. Revise implementing procedures to include inspections and tests are performed by personnel qualified in accordance with applicable ASME Code requirements.
8. Revise the implementing procedures to include if there are no ASME Code requirements, inspections will be conducted in accordance with site procedures, which will include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.
9. Revise implementing procedures to include, where quantitative data is available, identified degradation to be projected until the next scheduled 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.
10. Revise implementing procedures to include, if one of the inspections does not meet acceptance criteria, the cause of the aging effect for each applicable material and environment to be either corrected by repair or replacement for all components constructed of the same material and exposed to the same environment or additional inspections will be conducted. The number of increased inspections will be determined in accordance with the site's Corrective Action Program; however, no fewer than five additional inspections will be conducted for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less. 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 ensure corrective actions appropriately address the associated causes. For BFN, the additional inspections will include inspections at all the units with the same material, environment, and aging effect combination.

These enhancements will be implemented no later than six months prior to the subsequent period of extended operation.

A.2.1.13 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

The BFN Inspection of Overhead Heavy Load and Light Load (Related To Refueling) Handling Systems aging management program is an existing condition monitoring program that manages the effects of loss of material due to corrosion and wear, cracking, deformation, and indications of loss of preload for load handling bridges, structural members, structural components, and bolted connections. Procedures and controls implement the guidance on the control of overhead heavy load cranes specified in NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants.” The program utilizes periodic visual inspections as described in the ASME B30 series of standards for inspection, detection of aging effects, evaluation, and repair of aging effects.

The Inspection of Overhead Heavy Load and Light Load (Related To Refueling) Handling Systems aging management program will be enhanced as follows:

1. Revise the implementing procedures to ensure surface conditions are monitored by visual inspection to provide reasonable assurance that 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.

2. Revise the implementing procedures to ensure bolted connections are monitored by visual inspection to provide reasonable assurance that loss of material, cracking, and loose bolts, missing or loose nuts, and other conditions indicative of loss of preload are not occurring.
3. Revise implementation procedures to ensure aging effects will be detected for bridges, structural members, and structural components by visually inspecting for loss of material due to general corrosion; deformation; cracking, and wear.
4. Revise implementation procedures to ensure aging effects will be detected for bolted connections by visually inspecting for loss of material due to general corrosion; cracking; and loose or missing bolts or nuts, and other conditions indicative of loss of preload.
5. Revise implementation procedures to require visual inspection activities of in-scope load handling systems to be performed by qualified personnel.
6. Revise implementation procedures to ensure any visual indication of loss of material, deformation, or cracking, and any visual sign of loss of bolting preload will be evaluated for acceptance criteria according to ASME B30.2-1976 as well as other appropriate standards in the ASME B30 series including B30.11-1988, “Monorails and Underhung Cranes,” B30.16-1973, “Overhead Underhung and Stationary Hoists,” B30.10-1975, “Hooks,” and B30.17-1980, “Cranes and Monorails With Underhung Trolley or Bridge.”
7. Revise implementing procedures to ensure any repairs to in-scope load handling systems will be performed as specified in ASME B30.2-1976 as well as other appropriate standards in the ASME B30 series including B30.11-1988, B30.16-1973, B30.10-1975, and B30.17-1980.

These program enhancements will be implemented no later than six months prior to the subsequent period of extended operation.

A.2.1.14 Compressed Air Monitoring

The BFN Compressed Air Monitoring aging management program is an existing program that consists of condition monitoring (inspection and testing of the system) and preventive monitoring (air quality at various locations in the system is monitored to ensure that oil, water, rust, dirt, and other contaminants are kept within specified limits).

The Compressed Air Monitoring Program is based on NRC Generic Letter 88-14, “Instrument Air Supply System Problems Affecting Safety-Related Equipment,” and the Institute of Nuclear Power Operations Significant Operating Experience Report 88-01, “Instrument Air System Failures.” The Compressed Air Monitoring Program also incorporates provisions conforming to the guidance of the EPRI TR-108147, “Instrument Air Systems, A Guide for Power Plant Maintenance Personnel.” The program incorporates the guidelines of ANSI/ISA-S7.0.01-1996, “Quality Standard for Instrument Air,” and EPRI TR-108147, “Compressor and Instrument Air System Maintenance Guide,” and will use the guidelines of ASME OM-2012, Division 2, Part 28, “Performance Testing of Instrument Air Systems in Light-Water Reactor Power Plants.”

Program activities include air quality checks at various locations to ensure the dew point, particulates, and hydrocarbons are maintained within specified limits and includes inspections of the internal surfaces of compressed air system components for signs of loss of material due to corrosion.

The monitoring methods are effective in detecting the applicable aging effects, and the frequency of monitoring will be adequate to prevent significant age-related degradation. Deficiencies are documented in the Corrective Action Program and evaluations are performed for test or inspection results that do not satisfy established criteria.

Compressed Air Monitoring Program will be enhanced to include the Emergency Diesel Generator Starting Air System to ensure that periodic inspection and replacement of components are performed to prevent or mitigate aging degradation.

The Compressed Air Monitoring aging management program will be enhanced as follows:

1. Revise implementing procedures to manage the aging effects of loss of material due to corrosion in compressed air system components located downstream of the compressed air system air dryers, or for components exposed to an internal gas environment (e.g., nitrogen-filled accumulators).
2. Revise implementing procedures for Compressed Air Monitoring program to include the Emergency Diesel Generator Starting Air System.
3. Revise implementing procedures to incorporate guidelines for moisture and other corrosive contaminants limits based on ASME OM-2012, Division 2, Part 28, “Performance Testing of Instrument Air Systems in Light-Water Reactor Power Plants,” for inspection frequency and inspection methods.
4. Revise implementing procedures to include opportunistic visual inspections of accessible internal surfaces are performed for signs of corrosion and abnormal corrosion products that might indicate a loss of material within the system.
5. Revise implementing procedures to add opportunistic visual inspections of component internal surfaces exposed to an air-dry environment will be performed for signs of loss of material due to corrosion.
6. Revise implementing procedures to require qualification for personnel conducting visual inspection in accordance with site procedures.
7. Revise implementing procedures to ensure in-line dew point will be checked daily to determine whether moisture content is within the recommended range.
8. Revise implementing procedures to require trending of dew points being monitored and check for unusual trends in accordance with guidelines based on ASME OM-2012, Division 2, Part 28.
9. Revise implementing procedures to ensure that effects of corrosion are monitored by visual inspection. Test data are analyzed and compared to data from previous tests to provide for the timely detection of aging effects on passive components.
10. Revise implementing procedures to perform visual inspections which will ensure internal surfaces do not show signs of corrosion (general, pitting, and crevice) that could indicate the potential loss of function of the component. Suppliers' certifications can be used to demonstrate that bottled gases meet acceptable quality standards.
11. Revise implementing procedures to require corrective actions to be taken if any parameters, such as moisture content in the system air, are out of acceptable ranges, or if corrosion is identified on internal surfaces.

These program enhancements will be implemented no later than six months prior to the subsequent period of extended operation.

A.2.1.15 Fire Protection

The BFN Fire Protection aging management program is an existing condition and performance monitoring program that manages the identified aging effects for the fire barriers and the carbon dioxide systems and associated components in air-indoor uncontrolled and air-outdoor environments through the use of periodic inspections and functional testing to detect aging effects prior to loss of intended functions. System functional tests and inspections are performed in accordance with guidance from National Fire Protection Association Codes and Standards. The program applies to piping, piping components, and fire barriers (doors and dampers, penetration seals and walls). Fire Protection program component materials consist of carbon steel, galvanized steel, concrete, concrete block, grout, subliming and cementitious fireproofing, elastomers, and silicates.

The Fire Protection program monitoring methods are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent significant degradation. The program utilizes visual inspections of fire barrier penetration seals for signs of degradation such as loss of material, cracking/shrinking, wear, seal separation from walls and components, separation of layers of material, and changes in material properties through periodic inspection. The program specifies visual examinations of the fire barrier walls, ceilings, and floors in structures within the scope of subsequent license renewal for signs of degradation such as loss of material and cracking/spalling. Periodic visual inspections and functional tests are used to manage the aging effects of fire doors and fire damper assemblies. Inspection and testing frequencies are consistent with the BFN Fire Protection Requirements Manual. These inspections and tests are implemented through station procedures and recurring task work orders. Personnel performing inspections are qualified and trained to perform the inspection activities. Unacceptable conditions are entered into the Corrective Action Program for proper disposition.

The program will also provide for aging management of external surfaces of the carbon dioxide fire suppression system components that are within the scope of subsequent license renewal through periodic visual inspections for corrosion that may lead to loss of material. The program includes functional testing of the carbon dioxide fire suppression system components in accordance with the BFN Fire Protection Requirements Manual.

The Fire Protection aging management program will be enhanced as follows:

1. Revise implementing procedures to require performance of a visual inspection by fire protection qualified personnel of not less than 10 percent of each type of seal in walkdowns performed at a frequency in accordance with the NRC-approved fire protection program or at least once every refueling outage.
2. Revise implementing procedures to require qualification for personnel conducting visual inspection in accordance with site procedures for fire seals, fire barrier walls, ceilings, floors, and doors (e.g., wear, missing parts); fire damper assemblies; and other fire barrier materials including structural steel fire proofing.
3. Revise implementing procedures to require performance of visual inspections of the surface condition of the fire barriers including structural steel fire proofing at a frequency in accordance with the BFN NFPA 805 Fire Protection Requirements Manual.
4. Revise implementing procedures to require that results of inspections of the aging effects of cracking and loss of material on fire barrier penetration seals, fire barriers, fire damper

assemblies, and fire doors be trended to provide for timely detection of aging effects so that appropriate corrective actions be taken and:

- Where practical, identified degradation is projected until the next inspection.
- Results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation.

5. 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.
6. Revise implementing procedures to specify that inspection results are acceptable if there are no signs of degradation that could result in the loss of the fire protection capability due to loss of material. The specific acceptance criteria will include:
   - no visual indications (outside those allowed by approved penetration seal configurations) of cracking, separation of seals from walls and components, separation of layers of material, or ruptures or punctures of seals;
   - no significant indications of cracking and loss of material of fire barrier walls, ceilings, and floors and in other fire barrier materials;
   - no visual indications of missing parts, holes, and wear;
   - no visual indications of cracks or corrosion of fire damper assemblies;
   - no deficiencies in the functional tests of fire doors; and
   - no indications of excessive loss of material for the visual inspection of the carbon dioxide fire suppression system.
7. Revise implementing procedures to require, if any sign of degradation is detected (during the inspection of penetration seals) within that sample, the scope of the inspection will be expanded to include additional seals in accordance with the BFN Fire Protection Requirements Manual. In addition, if any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies will be adjusted to ensure the penetration seal's intended function is maintained until at least the performance of the next inspection.

These program enhancements will be implemented no later than six months prior to the subsequent period of extended operation

A.2.1.16 Fire Water System

The BFN Fire Water System aging management program is an existing condition monitoring program that manages the loss of material and flow blockage due to fouling associated with water-based fire protection system components. The program manages these aging effects through the use of system pressure monitoring, system header flushing, buried main supply flow testing, pump performance testing, hydrant flushing, sprinkler system and deluge system flow testing, visual inspections, and volumetric examinations performed using the guidance of NFPA 25, 2011 Edition “Inspection, Testing and Maintenance of Water-Based Fire Protection Systems.”.

External surfaces of buried fire main piping are evaluated for loss of material and cracking with aging effects managed as described in the Buried and Underground Piping and Tanks program (A.2.1.27). The fire main buried cement lined pipe aging effects such as cracking are managed by the Internal Coating/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (A.2.1.28).

Sprinkler heads for each unit will be replaced or inspected. Either sprinklers are replaced before reaching 50 years in-service or a representative sample of sprinklers from one or more sample areas is tested by using the guidance of NFPA 25, 2011 Edition. Additionally, if sprinklers are not replaced, they shall be inspected prior to the end of the specified service life and at specified intervals thereafter in accordance with NFPA 25.

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, will be subjected to augmented testing and inspections beyond those of Revision 0 of NUREG-2191, Table XI.M27-1. The augmented tests and inspections will be conducted on piping segments that cannot be drained or piping segments that allow water to collect. Dry pre-action sprinkler systems are air filled, and trip tested dry.

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. The system flow testing, visual inspections and volumetric inspections assure that aging effects are managed such that the system intended functions are maintained. Flow testing results will be reviewed and trended to identify degrading trends prior to loss of system function. The program ensures that testing and inspection activities have been performed and documented. Abnormal results are entered into the Corrective Action Program for review and resolution.

Inspections and tests are performed by personnel qualified in accordance with station procedures and programs to perform the specified task. The inspections and tests follow station procedures that include inspection parameters for items such as lighting, distance, offset, presence of protective coatings, and cleaning processes.

The Fire Water System aging management program will be enhanced as follows:

1. Revise implementing procedures to ensure that flushes are in accordance with NFPA 25, 2011 Edition, section 7.3.2.1, to mitigate or prevent fouling, which can cause flow blockage or loss of material, by clearing corrosion products and sediment.
2. Revise implementing procedures to perform periodic flow tests, flushes, internal and external visual inspections, and testing of sprinklers systems.
3. Revise implementing procedures to ensure that, when visual inspections are used to detect loss of material, the inspection technique will be capable of detecting surface irregularities that could indicate an unexpected level of degradation due to corrosion and corrosion product deposition. Where such irregularities are detected, follow-up volumetric wall thickness examinations will be performed. Additionally, volumetric wall thickness inspections will be conducted on portions of water-based fire protection system components that are periodically subjected to flow but are normally dry.
4. Revise implementing procedures to ensure that visual examinations of cementitious materials will be conducted to detect indications of loss of material and cracking that could affect the system's ability to maintain pressure.

5. Revise implementing procedures to meet guidelines of Revision 0 of NUREG-2191, Table XI.M27-1, Fire Water System Inspection and Testing Recommendations (NFPA 25, 2011 Edition, Guidelines).
6. Revise implementing procedures to ensure visual inspections are capable of evaluating: (i) the condition of the external surfaces of components, (ii) the conditions of the internal surfaces of components that could indicate wall loss or cracking, and (iii) the inner diameter of the piping as it applies to the design flow of the fire protection system (i.e., to verify that corrosion product buildup has not resulted in flow blockage due to fouling). Internal visual inspections used to detect loss of material are capable of detecting surface irregularities that could be indicative of an unexpected level of degradation due to corrosion and corrosion product deposition. Where such irregularities are detected, follow-up volumetric examinations will be performed.
7. Revise implementing procedures to ensure augmented tests and inspections are conducted on piping segments that cannot be drained or piping segments that allow water to collect:
   - In each 5-year interval, beginning 5 years prior to the subsequent period of extended operation, either conduct a flow test or flush sufficient to detect potential flow blockage, or conduct a visual inspection of 100 percent of the internal surface of piping segments that cannot be drained or piping segments that allow water to collect.
   - In each 5-year interval of the subsequent period of extended operation, 20 percent of the length of piping segments that cannot be drained or piping segments that allow water to collect is subject to volumetric wall thickness inspections. Measurement points are obtained to the extent that each potential degraded condition can be identified (e.g., general corrosion, microbiologically influenced corrosion). The 20 percent of piping that is inspected in each 5-year interval is in different locations than previously inspected piping.
   - If the results of a 100-percent internal visual inspection are acceptable, and the segment is not subsequently wetted, no further augmented tests or inspections are necessary.

   For portions of the normally dry piping that are configured to drain (e.g., pipe slopes towards a drain point) the tests and inspections of Revision 0 of NUREG-2191, Table XI.M27-1 do not need to be augmented.
8. Revise implementing procedures to require qualification for personnel conducting visual inspection in accordance with site procedures. The inspections and tests will follow site procedures that include inspection parameters for items such as lighting, distance, offset, presence of protective coatings, and cleaning processes.
9. Revise implementing procedures to ensure that results of flow testing (e.g., buried and underground piping, fire mains, and sprinkler), flushes, and wall thickness measurements are monitored and trended. Degradation identified by flow testing, flushes, and inspections will be evaluated.
10. Revise implementing procedures to ensure that inspections with quantitative results, degradation identified will be projected until the next scheduled inspection. Results will be evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation. 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.

11. Revise implementing procedures to specify acceptance criteria for minimum design wall thickness, and for loose fouling products in systems that could cause flow blockage in the sprinklers or deluge nozzles.
12. Revise implementing procedures to ensure that if the presence of sufficient foreign organic or inorganic material to obstruct pipe or sprinklers is detected during pipe inspections, the material will be removed and the inspection results will be entered into the site's Corrective Action Program for further evaluation.
13. Revise implementing procedures to ensure that 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 acceptance criteria due to current or projected degradation (i.e., trending) additional tests will be conducted. The number of increased tests will be determined in accordance with the site's corrective action process; however, there will be no fewer than two additional tests for each test that did not meet acceptance criteria. The additional inspections will be completed within the interval (i.e., 5 years, annual) in which the original test was conducted. If subsequent tests do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of tests. At BFN, the additional tests will include at least one test on one of the other units on site with the same material, environment, and aging effect combination.
14. Revise implementing procedures to ensure that an evaluation be conducted to determine if deposits need to be removed to determine if loss of material has occurred. When loose fouling products that could cause flow blockage in the sprinklers is detected, a flush will be conducted in accordance with the guidance in NFPA 25, 2011 Edition, Appendix D.5, “Flushing Procedures.” If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies will be adjusted as determined by the site's Corrective Action Program.

Program enhancements, associated with inspections/tests required to be implemented prior to the subsequent period of extended operation, will be implemented prior to performance of the required inspections/tests. Remaining program enhancements will be implemented no later than six months prior to the subsequent period of extended operation. Inspections/tests that are to be completed prior to the subsequent period of extended operation will be completed no later than five years prior to the subsequent period of extended operation.

A.2.1.17 Outdoor and Large Atmospheric Metallic Storage Tanks

The BFN Outdoor and Large Atmospheric Metallic Storage Tanks aging management program is an existing condition monitoring program that manages aging effects associated with in-scope outdoor aboveground tanks constructed on concrete or soil. BFN has no indoor, large volume tanks containing water designed with internal pressures approximating atmospheric pressure that are sited on concrete or soil, and no indoor tanks that sit on, or are embedded in concrete, where specific operating experience indicates that the tanks surfaces are periodically exposed to moisture. The scope of this program includes the Unit 1 condensate storage tank, Unit 2 condensate storage tank, the Unit 3 condensate storage tank. These tanks contain treated water, are constructed of carbon steel, are not insulated, are coated both internally and externally as a preventive measure to mitigate corrosion. Each tank is supported on a foundation consisting of a fiber board on a concrete ring, under the perimeter of the tank bottom, which surrounds a bed of compacted sulfur free oiled sand. As such, the bottoms of the tanks are inaccessible for direct visual inspection.

The program manages loss of material by conducting periodic internal and external visual inspections on a frequency of 10 years or less. Cracking is not a predicted aging effect due to the carbon steel construction. Thickness measurements of tank bottoms are conducted to ensure that significant degradation is not occurring. Inspections and tests are performed by personnel qualified in accordance with site procedures and programs to perform the specified task. Volumetric inspections are within the scope of the ASME Code and will follow procedures consistent with the ASME Code. All other inspections and testing are to follow site procedures that include inspection parameters for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. The periodic inspection results are compared to acceptance criteria and include trending to allow corrective action to be taken prior to loss of intended function.

The Outdoor and Large Atmospheric Metallic Storage Tanks aging management program will be enhanced as follows:

1. Revise implementing procedures to require tank inspections of inside surfaces to be conducted in accordance with Table B.2.1.17-1, “Tank Inspection Recommendations,” and the associated table notes. Table B.2.1.17-1 and the associated table notes will be added to the applicable procedure(s). The periodic inspections of the interior and bottom of the condensate storage tanks will manage the effects of corrosion on the intended function of these tanks.
2. Revise implementing procedures to require periodic visual inspections of tank exterior metallic surfaces to detect degradation at each outage, every two years, to confirm that paint and coatings are intact.
3. Revise implementing procedures to require volumetric inspections of the tank bottoms whenever the tank is drained, or at intervals in accordance with Table B.2.1.17-1, “Tank Inspection Recommendations,” to determine potential loss of material of tank bottoms. Table B.2.1.17-1 and the associated table notes will be added to the applicable procedure(s).
4. Revise implementing procedures to note when inspections are conducted on a sampling basis, subsequent inspections are conducted in different locations unless the program states the basis for why repeated inspections will be conducted in the same location.
5. Revise implementing procedures to ensure volumetric inspections will be consistent with the ASME Code. All other inspections and testing are to follow site procedures that include inspection parameters for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.
6. Revise implementing procedures to require identified degradation, where practical, to be projected until the next scheduled inspection.
7. Revise implementing procedures to require results to be evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation.
8. Revise implementing procedures to require additional inspections to be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending). The number of increased inspections is determined in accordance with the site's corrective action process; however:
   - For inspections where only one tank of a material, environment, and aging effect was inspected, all tanks in that grouping will be inspected.

- For other sampling based inspections (e.g., 20 percent, 25 locations) the smaller of five additional inspections or 20 percent of the inspection population is conducted. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause is conducted to determine the further extent of inspection. The additional inspections include inspections at all of the units with the same material, environment, and aging effect combination.
- The timing of the additional inspections is based on the severity of the degradation identified and is commensurate with the potential for loss of intended function. However, with the exception of external visual inspections, the additional inspections are completed within the interval in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the 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. External visual inspections are conducted within the original refueling outage interval.
- If any projected inspection results do not meet the acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the site's Corrective Action Program. However, for one time inspections that do not meet the acceptance criteria, inspections are subsequently conducted at least at 10 year inspection intervals.

These program enhancements will be implemented prior to beginning inspections within 10 years before the subsequent period of extended operation. The one-time inspections and initial periodic inspections are required to be performed within 10 years prior to the subsequent period of extended operation, and no later than 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.

A.2.1.18 Fuel Oil Chemistry

The BFN Fuel Oil Chemistry aging management program is an existing mitigative and condition monitoring program that includes activities which provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of 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 the BFN Technical Specifications, Technical Requirements Manual, and ASTM guidelines. 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.

The Fuel Oil Chemistry aging management program will be enhanced as follows:

1. Revise implementing procedures to require, for each Diesel Generator 7-Day Fuel Oil Tank and the Diesel Driven Fire Pump Fuel Oil Tank bottom surfaces, that UT inspections be performed at least once prior to the subsequent period of extended operation, at least once every 10 years during the subsequent period of operation, and if degradation is identified, UT examination of the tank bottom will be performed, the results analyzed and corrective actions taken, if necessary, to ensure integrity until the next scheduled inspection.
2. Revise implementing procedures to require, prior to the subsequent period of extended operation, performance of a one-time inspection of system components, exposed to diesel

fuel oil, constructed of materials other than the steel in accordance with the BFN One-Time Inspection program (A.2.1.20).

3. Revise implementing procedures to require that results of inspections be trended to provide for timely detection of aging effects and, where practical, require that identified degradation be projected until the next inspection.
4. Revise implementing procedures to require that thickness measurements of each Diesel Generator 7-Day Fuel Oil Tank and the Diesel Driven Fire Pump Fuel Oil Tank bottom surfaces are evaluated against the design thickness and corrosion allowance.
5. Revise implementing procedures to require that corrective actions are taken to prevent recurrence when the specified limits for fuel oil standards are exceeded or when water is drained during periodic surveillance. If accumulated water is found in a fuel oil storage tank, it is immediately removed. In addition, when the presence of biological activity is confirmed, or if there is evidence of MIC, a biocide, in the form of a multi-function diesel fuel oil inhibitor may be added to fuel oil, or the fuel oil replaced.

These program enhancements will be implemented no later than six months prior to the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.

A.2.1.19 Reactor Vessel Material Surveillance

The BFN Reactor Vessel Material Surveillance aging management program is an existing condition monitoring program that manages the loss of fracture toughness due to neutron embrittlement of the ferritic reactor vessel beltline materials in a reactor coolant and neutron flux environment. The program utilizes surveillance capsules that are located near the inside wall of the reactor vessel beltline region to duplicate the neutron spectrum, temperature history, and neutron fluence of the reactor vessel inner surface. The resulting lead factor allows the surveillance capsules to achieve a neutron fluence exposure earlier than the reactor vessel allowing the surveillance capsules to be withdrawn and tested prior to the reactor vessel reaching the neutron fluence of interest.

The Reactor Vessel Material Surveillance program meets the requirements of 10 CFR Part 50, Appendix H, via BFN's participation in the Boiling Water Reactor Vessel and Internals Project (BWRVIP) Integrated Surveillance Program (ISP) in lieu of a plant-specific capsule removal and testing schedule. For the subsequent period of operation, the program will implement BWRVIP-321 Revision 1-A, “Boiling Water Reactor Vessel and Internals Project, Plan for Extension of the BWR Integrated Surveillance (ISP) Through the Second License Renewal (SLR),” to maintain compliance with the requirements of 10 CFR Part 50, Appendix H.

The program provides sufficient material data and dosimetry to: (a) monitor irradiation embrittlement neutron fluences greater than the projected neutron fluence at the end of the subsequent period of extended operation, and (b) provide adequate dosimetry monitoring during the operational period.

Surveillance capsules are withdrawn, tested, and results reported in accordance with 10 CFR Part 50, Appendix H, and ASTM E 185-82. Any changes to the surveillance capsule withdrawal schedule, including changing the status of standby capsule, must be approved by the NRC prior to implementation per 10 CFR Part 50, Appendix H. Specimens from tested capsules and withdrawn untested capsules are maintained in storage for possible reconstitution or reinsertion.

The Reactor Vessel Material Surveillance aging management program will be enhanced as follows:

1. Implement BWRVIP-321 Revision 1-A to maintain compliance with 10 CFR 50 Appendix H during the subsequent period of extended operation.

The program enhancement will be implemented no later than six months prior to the subsequent period of extended operation.

A.2.1.20 One-Time Inspection

The BFN One-Time Inspection aging management 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 aging management program 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 will include: (a) determination of the sample size of components to be inspected based on an assessment of materials of fabrication, environments, plausible aging effects, and OE; (b) identification of the inspection locations in the system or component based on the potential for the aging effect to occur; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined; and (d) 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.

When one-time inspections fail to meet the established acceptance criteria, the Corrective Action Program will be used to schedule, track, and trend the appropriate corrective actions and follow up inspections.

Periodic inspections instead of this program will be 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 will be conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset, and surface conditions.

This new aging management program will be implemented prior to beginning inspections within 10 years before the subsequent period of extended operation. The inspections that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.

A.2.1.21 Selective Leaching

The BFN Selective Leaching aging management program is a new condition monitoring program that includes a one-time inspection for components exposed to a closed-cycle cooling water or treated water environment when plant-specific operating experience has not revealed selective leaching in these environments. Opportunistic and periodic inspections are conducted for raw water, waste water, soil, and groundwater environments, and for closed-cycle cooling water and 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 are conducted. Periodic destructive examinations of components for physical properties (i.e., degree of dealloying, depth of dealloying, through-wall thickness, and chemical composition) are conducted for components exposed to raw water, waste water, soil, and groundwater environments, or for closed-cycle cooling water and treated water environments when plant-specific operating experience has revealed selective leaching in these environments. Inspections and tests are 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 conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset and surface conditions. 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 are performed.

The new program will be implemented prior to beginning inspections within 10 years before the subsequent period of extended operation. The inspections that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.

A.2.1.22 ASME Code Class 1 Small-Bore Piping

The BFN ASME Code Class 1 Small Bore Piping aging management program is a new conditioning monitoring program augments the existing ASME Code, Section XI requirements and is applicable to small-bore ASME Code Class 1 piping and systems with a nominal pipe size (NPS) diameter less than 4 inches and greater than or equal to 1 inch ($1 \leq$ NPS < 4). This program provides a one-time volumetric inspection of a sample of this Class 1 piping to manage cracking due to stress corrosion cracking or thermal or vibratory fatigue. This program includes pipes, full penetration (butt) and partial penetration (socket) welds. The program includes measures to verify that degradation is not occurring, thereby either confirming that there is no need to manage aging-related degradation or validating the effectiveness of any existing program for the subsequent period of extended operation. The one-time inspection program for ASME Code Class 1 small-bore piping includes locations that are susceptible to cracking. This program is applicable to systems that have not experienced cracking of ASME Code Class 1 small-bore piping. This program can also be used for systems that experienced cracking but have implemented design changes to effectively mitigate cracking.

Volumetric examinations will employ techniques that have been demonstrated to be capable of detecting flaws and discontinuities in the examination volume of interest. Destructive examination methods may be used in lieu of volumetric examination methods. The program includes measures to verify that degradation is not occurring; thereby either to confirm that there is no need to further manage aging-related degradation or to validate the effectiveness of existing programs and practices for the subsequent period of extended operation.

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. For BFN, the program provides for a one-time inspection of a sample of the population of welds (butt welds and socket welds) and periodic inspections as required by the BFN ISI Program.

Should evidence of cracking be revealed by a one-time inspection, the corrective actions will include examinations of additional ASME Code Class 1 small-bore piping welds to meet the intent of ASME Code, Section XI, Subarticle IWB-2430. If any new OE or evaluation of the one-time examinations detect unacceptable flaws or relevant conditions, periodic examinations will be implemented in accordance with Category C of NUREG-2191, Revision 0, Table XI.M35-1.

This new program will be implemented no later than six years prior to the subsequent period of extended operation. The one-time inspections are required to be performed within the six years prior to the subsequent period of extended operation, and no later than 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.

A.2.1.23 External Surfaces Monitoring of Mechanical Components

The BFN External Surfaces Monitoring of Mechanical Components aging management program is a new condition monitoring program that manages loss of material, cracking, hardening or loss of strength (of elastomeric components), and reduced thermal insulation resistance.

Periodic visual inspections, not to exceed one refueling cycle, of metallic, polymeric, and insulation jacketing (insulation when not jacketed) will be conducted. Coating degradation, such as cracking, flaking, or blistering; evidence of insulation damage or wetting, leakage, and accumulation of debris on heat exchanger surfaces, will be used as an indicator of possible degradation on underlying surfaces of the component. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength will be used to augment the visual examinations conducted under this program. There are no cementitious components within the scope of this program.

Surface examinations or ASME Code, 2007 Edition through 2008 Addenda as modified by 10 CFR 50.55a, Section XI, Appendix VIII VT-1 examinations will be conducted to detect cracking of copper alloy (>15% Zn or >8% Al), stainless steel, and aluminum components on a sampling basis 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.

Inspections not conducted in accordance with ASME Code, 2007 Edition through 2008 Addenda as modified by 10 CFR 50.55a, Section XI, Appendix VIII VT-1 examinations requirements will be conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset, and surface conditions. Acceptance criteria will be such that the component will meet its intended function until the next inspection or the end of the subsequent period of extended operation. Qualitative acceptance criteria will be clear enough to reasonably assure a singular decision is derived based on observed conditions.

This new program will be implemented no later than six months prior to the subsequent period of extended operation.

A.2.1.24 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

The BFN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components aging management program is a new condition monitoring program that will manage loss of material and cracking, as well as hardening or loss of strength of polymeric materials. Reduction of heat transfer due to fouling will also be managed. This program will consist of visual inspections of all accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components, and other components. Surface examinations or ASME Code, 2007 Edition through 2008 Addenda as modified by 10 CFR 50.55a, Section XI, Appendix VIII VT-1 examinations will be conducted to detect cracking of stainless steel. Applicable environments include air, gas, condensation, diesel exhaust, water, and fuel oil.

These internal inspections will be performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. At a minimum, in each 10-year period during the 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 25 components per population will be inspected at each unit, unless the technical justification allows for reducing sample size. Where practical, the inspections will focus on the bounding or lead components most susceptible to aging because of time in service, and severity of operating conditions. Opportunistic inspections will continue in each period despite meeting the sampling limit. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength will be used to augment the visual examinations conducted under this program.

Inspections not conducted in accordance with ASME Code, 2007 Edition through 2008 Addenda as modified by 10 CFR 50.55a, Section XI, Appendix VIII requirements will be conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset and surface conditions. Acceptance criteria will be such that the component will meet its intended function until the next inspection or the end of the subsequent period of extended operation. Qualitative acceptance criteria will be clear enough to reasonably assure a singular decision is derived based on observed conditions.

This new program will be implemented no later than six months prior to the subsequent period of extended operation.

A.2.1.25 Lubricating Oil Analysis

The BFN Lubricating Oil Analysis aging management program is a new condition monitoring program that provides monitoring of oil in piping, piping components, gear boxes, heat exchangers, and tanks within the scope of license renewal exposed to a lubricating oil environment. This program provides reasonable assurance that the oil environment in the mechanical systems is maintained to the required quality, and the oil systems are maintained free of contaminants (primarily water and particulates), thereby preserving an environment that is not conducive to loss of material or reduction of heat transfer. Testing activities include sampling and analysis of lubricating oil for detrimental contaminants. The presence of water or particulates may also indicate in-leakage and corrosion product buildup.

This new program will be implemented no later than six months prior to the subsequent period of extended operation.

A.2.1.26 Monitoring of Neutron-Absorbing Materials Other Than Boraflex

The BFN Monitoring of Neutron-Absorbing Materials Other Than Boraflex aging management program is a new condition monitoring program that includes periodic inspection, testing, monitoring, and analysis of test coupons of the neutron-absorbing material in the spent fuel storage racks to assure that the required five percent subcriticality margin is maintained. This program consists of inspecting the physical condition of the neutron-absorbing material for visual appearance, dimensional measurements, weight, geometric changes (e.g., bubbling, blistering, corrosion, pitting, cracking, and flaking), and boron areal density as observed from coupons, to monitor for reduction of neutron absorbing capacity, loss of material, and change in dimension.

This new program will be implemented no later than 6 months prior to the subsequent period of extended operation.

A.2.1.27 Buried and Underground Piping and Tanks

The BFN Buried and Underground Piping and Tanks program is an existing aging management program that manages the aging effects associated with the external surfaces of buried and underground piping such as loss of material and cracking. The program addresses buried and underground piping composed of any material, including metallic materials, that are within the scope of SLR in the Condensate Demineralized Water System, the Residual Heat Removal System, the Raw Service Water System, the High Pressure Fire Protection System, the Condenser Circulating Water System, the Containment System, the Standby Gas Treatment System, the Emergency Equipment Cooling Water System, the Radwaste System, the Containment Atmosphere Dilution System, and the Hardened Containment Venting System. BFN does not have any buried or underground polymeric or cementitious piping, and there are no buried or underground tanks within the scope of this program. In addition, BFN does not have any underground copper alloy materials in the scope of the program. The program also manages loss of material due to corrosion of piping system bolting within the scope of this program. Loss of material is monitored by visual inspection of the exterior surface and wall thickness measurements of the piping. Wall thickness is determined by a non-destructive examination technique such as UT.

The program also manages aging through preventive and mitigative actions (i.e., coatings or wrappings and backfill quality). The number of inspections for each 10-year inspection period, commencing within 10 years prior to the subsequent period of extended operation is based on the effectiveness of the preventive and mitigative actions. Cathodic protection is not utilized at BFN.

Periodic visual inspections of external surfaces of buried components are performed to check for evidence of coating/wrapping damage, loss of material, and cracking. Periodic inspection of external surfaces of underground components is also performed to check for evidence of loss of material and cracking. The selection of locations of these inspections will be based on factors including site operating experience (OE), high-risk ranking, and results from soil analysis combined with results from pipe-to-soil surveys (soil corrosiveness of the environment in which the buried pipe to be inspected exists). Opportunistic visual inspections are also conducted for in-scope piping whenever they become accessible. Soil testing will be conducted in conjunction with the periodic direct inspections of buried piping. These inspections and tests will begin within

10 years before the subsequent period of extended operation and at least every 10 years during the subsequent period of extended operation. Inspections will be 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 intended function when the material loss rate is extrapolated to the end of the subsequent period of extended operation, an increase in the sample size will be conducted.

The Buried and Underground Piping and Tanks aging management program will be enhanced as follows:

1. Revise implementing procedures to explicitly include the Condensate Demineralized Water System and the Radwaste System within the scope of the SLR Buried and Underground Piping and Tanks Aging Management Program.
2. Revise implementing procedures to require that the inspections of buried and underground piping be conducted in accordance with the below Table, with the inspections evenly distributed among the three BFN units, and include inspection of fittings (e.g., elbows, tees, etc.) to capture factory applied to field applied coating interfaces and the associated field applied coatings used at these locations. They will further require that the planned inspections of buried and underground piping and the associated field applied coatings used at these locations be conducted, as a minimum, by visual examination of the external surfaces of pipe or coatings.

Material	Environment	Number of Inspections	Notes
Steel	Soil/Buried	6	Category E - 6 inspections
Steel	Concrete	2	The concrete will be inspected for cracking, which could indicate piping degradation
Stainless Steel	Soil	2	None
Stainless Steel	Concrete	2	The concrete will be inspected for cracking, which could indicate piping degradation

   There will be 6 inspections within the 10-year period prior to entry into the subsequent period of extended operation, starting with the first 6 locations from Table B.2.1.27-1 and shown on Figure B.2.1.27-1 (Dig 1 through Dig 6). These inspections are in addition to any opportunistic inspections for this period. There will be 6 planned inspections for the first 10-year period of the subsequent period of extended operation and will be based on the next 6 locations from Table B.2.1.27-1 and shown on Figure B.2.1.27-1 (Dig 7 through Dig 12), however these locations may be adjusted based on OE from the inspections of the first 6 locations above or industry OE. These inspections will be in addition to any opportunistic inspections for this period. And then, based on the results of these 12 excavations and any opportunistic inspections or applicable OE, 6 additional locations will be selected and inspected for the last 10-year period of the subsequent period of extended operation.
3. Revise implementing procedures to require that soil testing using the guidance in the EPRI Report 3002018353, Revision 2, “Buried and Underground Piping and Tank Reference Guide,” be conducted in conjunction with the periodic direct inspections of buried piping.
4. Revise implementing procedures to require that pipe inspection locations be determined based on factors including site OE, high-risk ranking (BPWORKS™), and indirect inspection results (soil analyses, close-interval surveys, and area potential earth current surveys),

combined with results from pipe-to-soil potential surveys. Consideration is also given to characteristics such as coating type (i.e., material type), coating condition, backfill characteristics, soil resistivity, pipe contents, and pipe function.

5. Revise implementing procedures to require that opportunistic inspections be conducted for in-scope piping whenever they become accessible.
6. Revise implementing procedures to require that inspections in addition to those listed in the above Table be performed, if appropriate, in response to plant-specific OE.
7. Revise implementing procedures to require that inspections be documented (including as-found and as-left inspection results).
8. Revise implementing procedures to require that inspections be performed by a qualified coatings inspector for evaluation of the condition of the coating. The coatings inspector will be qualified in accordance with TVA Nuclear Power General Engineering Specification G-55, Technical and Programmatic Requirements for the Protective Coating Program for TVA Nuclear Plants. Evaluation of coating failures and non-conforming conditions will be performed by a Coatings Subject Matter Expert, who is qualified via the completion of industry recognized formal coatings training, such as the EPRI Comprehensive Coatings Course and the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course, or equivalent courses as identified in NUREG-2191 AMP XI.M41 Section 6.a.
9. Revise implementing procedures to require that pipe-to-soil potential readings are acquired at the excavation and adjacent to the excavation location to determine the potential for galvanic corrosion cells and to assess the effectiveness of the coating system. Alternate pipe-to-soil potential measurement locations should be selected where excavation locations are in the immediate vicinity of previously performed pipe-to-soil potential readings. Alternate pipe-to-soil potential measurement locations should be chosen to provide additional information applicable to selection of future excavation locations. A minimum of six pipe-to-soil potential readings should be acquired during each 10-year period (10 years prior to the subsequent period of extended operation and the first 10 years of the subsequent period of extended operation) and may be acquired anytime during the 10-year period of the scheduled dig (preferably prior to the actual excavation).
10. Revise implementing procedures to require that new and replacement field applied coating shall meet the guidance of Table 1 of NACE SP0169-2007.
11. Revise implementing procedures to require that new and replacement backfill shall meet the guidance of NACE SP0169-2007, Section 5.2.3.
12. Revise implementing procedures to require that backfill quality be demonstrated during the subsequent period of extended operation by examining the backfill while conducting the inspections of buried piping and by review of plant records.
13. Revise implementing procedures to revise the High Pressure Fire Protection System Ring Header Flow Test to (1) clarify that the test is being performed in accordance with Section 7.3 of NFPA 25 to satisfy the requirements of GALL-SLR AMP XI.M41 Element 2, Preventive Actions, Section 2.g.iii, Element 3, Parameters Monitored or Inspected, Section 3.f.i, and Element 4, Detection of Aging Effects, Section 4.e.i, (2) the frequency of the test will be increased to require at least one test be performed in each 1-year period during the subsequent period of extended operation, and (3) state that a reduction in available flow rate below the minimum required flow rate for the test will be used as an indication of possible fire main leakage.

14. Revise implementing procedures to require that results of periodic flow testing of fire mains in accordance with NFPA 25, which do not satisfy the minimum required flow rate for the test, to be considered as indication of possible fire main leakage and entered into the Corrective Action Program for trending and resolution.
15. Revise implementing procedures to state that flow test results for fire mains are acceptable if the results are in accordance with NFPA 25, Section 7.3.
16. Revise implementing procedures to require that visual inspections of the external surfaces of controlled low strength material backfill be performed, in place of the visual inspections of the external surface condition of buried piping and associated coatings, to detect potential cracks that could admit groundwater to the surface of the component. If alternatives to visual inspections are performed, they will be performed in accordance with NUREG-2191, Section XI.M41, Subsection 4.e.
17. Revise implementing procedures to require that monitoring of the surface condition of coatings and wraps will be conducted for all excavations of buried pipe to determine if the coatings and wraps are intact, well adhered, and otherwise sound such that aging effects would not be expected for the base material of the component.
18. Revise implementing procedures to require that monitoring of the surface condition of the buried and underground piping and components be conducted to detect indications of aging effects such as general, pitting, crevice, and microbiologically influenced corrosion (MIC), and that the surface condition of the component be examined when it is exposed, such as when coating damage is discovered.
19. Revise implementing procedures to require that volumetric nondestructive examination techniques, or including the use of pit depth gages or calipers for measuring wall thickness, will have been determined to be effective for the material, environment, and conditions (e.g., remote methods) to be examined, and will be confirmed to be capable of quantifying general wall thickness and the depth of pits.
20. Revise implementing procedures to require that when coating damage is discovered and the pipe is found to be degraded, wall thickness measurements will be conducted to detect potential loss of material.
21. Revise implementing procedures to require that any inspections performed to identify cracking due to stress corrosion cracking for stainless steel materials will use a method that has been determined to be capable of detecting cracking.
22. Revise implementing procedures to clarify that coatings will not have to be removed that: (a) are intact, well-adhered, and otherwise sound for the remaining inspection interval; and (b) exhibit small blisters that are few in number and completely surrounded by sound coating bonded to the substrate.
23. Revise implementing procedures to require that inspections for cracking be conducted on piping with degraded coating to assess the impact of cracks on the pressure boundary function of the component being visually inspected.
24. Revise implementing procedures to require that BFN will take soil samples prior to planned excavations to confirm that the chemistry of the backfill is nonaggressive.
25. Revise implementing procedures to require that visual inspections be supplemented with surface and/or volumetric nondestructive testing if evidence of wall loss beyond minor surface scale is observed.
26. Revise implementing procedures to state that when conducting inspections of buried components embedded in concrete backfill or engineered flowable fill used as backfill, the

backfill may be excavated and the pipe examined, or the soil around the backfill may be excavated and the cementitious material examined. Also state that the inspection will include excavation of the top surfaces and at least 50 percent of the side surface to visually inspect for cracks in the backfill that could admit groundwater to the external surfaces of the component. Additionally, require that when conducting inspection of backfill based on the number of inspections designated for that material type, 10 linear feet of the backfill be exposed for each inspection.

27. Revise implementing procedures to require that when plant-specific conditions result in transitioning to a higher number of inspections than originally planned at the beginning of a 10-year interval, the timing of the additional examinations will be based on the severity of the degradation identified and will be commensurate with the consequences of a leak or loss of function. However, in all cases, the expanded sample inspection will be completed within the 10-year interval in which the original inspection was conducted, or if this transition occurs in the latter half of the current 10-year interval, within 4 years after the end of the particular 10-year interval. Furthermore, these additional inspections conducted during the 4 years following the end of an inspection interval cannot also be credited towards the number of inspections required for the following 10-year interval. The number of inspections may be limited by the extent of piping subject to the observed degradation mechanism.
28. Revise implementing procedures to require that when conducting inspection of backfill based on the number of inspections designated for that material type, 10 linear feet of the backfill will be exposed for each inspection.
29. Revise implementing procedures to require that when piping inspections are based on the number of inspections in lieu of percentage of piping length, 10 feet of piping will be exposed for each inspection. Additionally, when the percentage of inspections for a given material type results in an inspection quantity of less than 10 feet, then 10 feet of piping will be inspected. Also, if the entire run of piping of that material type is less than 10 feet in total length, then the entire run of piping will be inspected.
30. Revise implementing procedures to state that opportunistic examinations of non-leaking pipes may be credited toward examinations if the location selection criteria are met. The use of guided wave ultrasonic examinations may not be substituted for the required inspections.
31. Revise implementing procedures to require that where wall thickness measurements are conducted, the results will be trended when follow up examinations are conducted.
32. Revise implementing procedures to explicitly require that, where practical, coating condition degradation will be projected until the next scheduled inspection, and that inspection/examination 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.
33. Revise implementing procedures, for coated piping, to require that there is either no evidence of coating degradation, or the type and extent of coating degradation is evaluated as insignificant by a Protective Coatings Subject Matter Expert who has completed industry recognized formal coatings training, such as the EPRI Comprehensive Coatings Course and the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course, or equivalent courses as identified in NUREG-2191 AMP XI.M41 Section 6.a.
34. Revise implementing procedures to require that measured wall thickness projected to the end of the subsequent period of extended operation meets minimum wall thickness requirements.

35. Revise implementing procedures to require that indications of cracking in metallic pipe be managed in accordance with the Corrective Action Program and require that indications of cracking in underground or buried in-scope piping be evaluated in accordance with applicable codes and plant-specific design criteria.
36. Revise implementing procedures to state that backfill is acceptable if the inspections do not reveal evidence that the backfill caused damage to the component's coatings or the surface of the component (if not coated).
37. Revise implementing procedures to state that cracks in cementitious backfill that could admit groundwater to the surface of the component are not acceptable.
38. Revise implementing procedures to require that where damage to the coating has been evaluated as significant and the damage was caused by nonconforming backfill, an extent of condition evaluation will be conducted to determine the extent of degraded backfill in the vicinity of the observed damage.
39. Revise implementing procedures to require that coated or uncoated metallic piping that is found to show evidence of corrosion will have the remaining wall thickness in the affected area determined to ensure that the minimum wall thickness is maintained. This may include different values for large area minimum wall thickness and local area wall thickness. If the wall thickness extrapolated to the end of the subsequent period of extended operation meets minimum wall thickness requirements, recommendations for expansion of sample size will not apply.
40. Revise implementing procedures to explicitly require that where the coatings, backfill, or the condition of exposed piping does not meet acceptance criteria, the degraded condition will be repaired, or the affected component will be replaced. In addition, where the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material is extrapolated to the end of the subsequent period of extended operation:
    - An expansion of sample size will be conducted.
    - The number of inspections within the affected piping categories will be doubled or increased by five, whichever is smaller.
    - If the acceptance criteria are not met in any of the expanded samples, an analysis will be conducted to determine the extent of condition and extent of cause.
    - The number of follow-on inspections will be determined based on the extent of condition and extent of cause.
    - The expansion of sample inspections may be halted in a piping system or portion of system that will be replaced within the 10-year interval in which the inspections were conducted or, if identified in the latter half of the current 10-year interval, within 4 years after the end of the 10-year interval.
41. Require that the section of underground carbon steel piping (in an isolation valve pit) in the Hardened Containment Venting System which is not coated consistent with GALL-SLR Element 2 for underground steel piping, will be coated in accordance with Table 1 of NACE SP0169-2007 prior to the subsequent period of extended operation.

These enhancements will be implemented prior to beginning inspections within 10 years before the subsequent period of extended operation. Inspections, tests, and installation of coatings that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.

A.2.1.28 Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

The BFN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks aging management program is a new condition monitoring program that includes visual inspections of internal coatings/linings of cast iron, ductile iron, stainless steel and carbon steel piping, piping components, valve bodies, tanks, and heat exchangers exposed to raw water, treated water, air, and condensation. There are no piping or components with internal coatings/linings in the program scope that are exposed to closed-cycle cooling water, treated borated water, waste water, fuel oil, and lubricating oil. This program is not used to manage the integrity of coatings applied to external surfaces of piping or components.

This program manages these aging effects for internal coatings by conducting periodic visual inspections of all coatings/linings applied to the internal surfaces of in-scope components where loss of coating or lining integrity could prevent satisfactory accomplishment of any of the component's, or downstream component's, current licensing basis intended functions.

Inspection results that do not satisfy established acceptance criteria are entered into the Corrective Action Program. The Corrective Action Program ensures that conditions adverse to quality are promptly corrected.

For tanks and heat exchangers, all accessible surfaces are inspected. Piping inspections are sampling-based. The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings are conducted in accordance with ASTM International Standards endorsed in Regulatory Guide 1.54, Revision 2, “Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants,” including guidance from the NRC 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 with the blisters being surrounded by sound material and with the size and frequency not increasing. Minor cracks in cementitious coatings are acceptable provided there is no evidence of debonding. All other degraded conditions are evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, physical testing is performed where physically possible (i.e., sufficient room to conduct testing) in conjunction with repair or replacement of the coating/lining.

This new program will be implemented prior to beginning inspections within 10 years before to the subsequent period of extended operation. Baseline inspections that are to be completed within 10 years prior to the subsequent period of extended operation will be completed no later than 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.

A.2.1.29 ASME Section XI, Subsection IWE

The BFN ASME Section XI, Subsection IWE aging management program is an existing condition monitoring program based on ASME Code and complies with the provisions of 10 CFR 50.55a. The program consists of periodic visual, surface, and volumetric examinations, where applicable, of metallic pressure-retaining components of steel containments for signs of degradation, damage, irregularities, and for coated areas distress of the underlying metal shell, and corrective actions. Acceptability of inaccessible areas of steel containment shell 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 aging management for the potential loss of material due to corrosion in the inaccessible areas of the BWR Mark I steel containment, including periodic ultrasonic test examinations of Units 1, 2, and 3 drywell liner plate near the sand bed region. In addition, the program includes, 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 that is inaccessible from one side. Results are compared with prior recorded results in acceptance of components for continued service.

The ASME Section XI Subsection IWE aging management program will be enhanced as follows:

1. Include the following components within the scope of the program:
   - dissimilar metal welds
   - bellows
2. 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, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” dated August 2014, will be used.
3. Revise implementing procedures to include monitoring of sand bed and refueling seal drains for water leakage on a weekly basis when the reactor cavity is filled with water.
4. Revise implementing procedures to include periodic monitoring to ensure the sand bed drains are kept clear to prevent moisture levels associated with accelerated corrosion rates in the exterior portion of the BWR Mark I steel containment drywell shell.
5. Revise implementing procedures to require a one-time volumetric examination of metal shell or liner surfaces that are inaccessible from one side, only if triggered by plant-specific operating experience. The trigger for this supplemental examination will be plant-specific occurrence or recurrence of measurable metal shell or liner corrosion (base metal material loss exceeding 10 percent 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 will consist of a sample of one-foot square locations that include both randomly-selected and focused areas most likely to experience degradation based on operaging experience and/or other relevant considerations such as environment. Any identified degradation will be addressed in accordance with the applicable provisions of the this aging management program. The sample size, locations, and any needed scope expansion (based on findings) for this one-time set of volumetric examinations will be determined on a plant-specific basis to demonstrate statistically with 95 percent confidence that 95 percent of the accessible portion of the containment liner is not experiencing corrosion degradation with greater than 10 percent loss of nominal thickness. Guidance provided in EPRI TR-107514 may be used for sampling considerations
6. Revise implementing procedures to state the requirements of ASME Code Section XI, Subsection IWE, and 10 CFR 50.55a are supplemented to perform surface examination (or

other applicable technique) in addition to visual examinations, to detect cracking in stainless steel penetration sleeves, dissimilar metal welds, bellows, and steel components that are subject to cyclic loading but have no current licensing basis fatigue analysis. Containment integrated leak rate (Type A) tests and local leak rate (Type B) tests performed by the 10 CFR 50 Appendix J program (A.2.1.31) are credited for detection of cracking of dissimilar metal weld penetrations and penetration bellows, respectively, in lieu of supplemental surface examinations.

7. Revise implementing procedures to carry forward Commitment No. NCO040006088, Enhance ASME Section XI, Subsection IWE program to perform a UT inspection of the sand bed area of the drywell liner of Units 1, 2, and 3. Subsequent periodic inspections will be performed on each unit prior to entry into the subsequent period of extended operation and at least once every 10 years thereafter.
8. Revise implementing procedures to include additional provisions to address identified degradation of weld pressure-retaining components that are subject to cyclic loading but do not have a fatigue analysis to undergo repair, rework, replacement, or justification for continued use by engineering evaluation.
9. Revise implementing procedures to specify the additional ASME code subsections identified within IWE-3000 for addressing the following conditions:
   - Areas identified with damage or degradation that exceed acceptance standards require an engineering evaluation or require correction by repair or replacement, and
   - For the containment steel shell or liner, material loss locally exceeding 10 percent of the nominal containment wall thickness or material loss that is projected to locally exceed 10 percent of the nominal containment wall thickness before the next examination are documented.
10. Revise implementing procedures to require a causal analysis for instances when sources of moisture cannot be identified in the inaccessible area on the exterior of the containment drywell shell
11. Revise implementing procedures to state that if moisture has been detected or suspected in the inaccessible area on the exterior of the containment drywell shell or the source of moisture cannot be determined subsequent to causal analysis, then:
    - Any components that are identified in the future as a source of moisture, will be added to the scope of SLR and if applicable, an aging management review will be performed.
    - Pursuant to Subsection IWE-1240, identify in the inspection program affected drywell surfaces requiring augmented examination for the subsequent period of extended operation in accordance with Table IWE-2500-1, Examination Category E-C.
    - Conduct augmented inspections of the identified drywell surfaces using examination methods that are in accordance with Subsection IWE-2500.
    - Demonstrate, through use of augmented inspections performed in accordance with Subsection IWE, that corrosion is not occurring or that corrosion is progressing so slowly that the age-related degradation will not jeopardize the intended function of the drywell shell through the subsequent period of extended operation.

These program enhancements will be implemented no later than six months prior to the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.

A.2.1.30 ASME Section XI, Subsection IWF

The BFN ASME XI, Subsection IWF aging management program is an existing condition monitoring program that implements requirements contained in 10 CFR 50.55a which imposes the inservice inspection (ISI) requirements of the ASME Code, Section XI, Rules for Inservice Inspection of Nuclear Power Plant Components, 2007 Edition with the 2008 Addenda, Subsection IWF, for Class 1, 2, 3 and MC component and piping supports. The BFN program is in accordance with ASME Section XI, Subsection IWF, as approved in 10 CFR 50.55a. Component and piping supports are selected for inspection in accordance with the ASME Code classification. The quantity of component supports selected for examination is increased as a result of discovered support deficiencies.

This program consists of periodic visual examination of piping and component supports for signs of degradation, evaluation of the examination results, and corrective actions for any identified deficiencies. This program recommends additional inspections beyond the inspections required by ASME Code Section XI, Subsection IWF. The additional inspection consist of a one-time inspection of an additional 5 percent of the sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports. This one-time inspection will be conducted within five years prior to entering the subsequent period of extended operation. For a sample of high-strength bolting in sizes greater than 1-inch nominal diameter, volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1 will be performed to detect cracking in addition to the VT-3 examination. This program will also emphasize proper selection of bolting material, lubricants, and installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. The program will also perform inspections of the seismic restraints in the RHRSW pump pit.

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.

The ASME Section XI Subsection IWF aging management program will be enhanced as follows:

1. Implementing procedures will be revised to ensure the scope of this program includes support members, structural bolting, high-strength structural bolting [actual measured yield strength greater than or equal to 150 ksi (1,034 MPa)], anchor bolts, welds, support anchorage to the building structure, accessible sliding surfaces, constant and variable load spring hangers, guides, stops, and vibration isolation elements.
2. Implementing procedures will be revised to ensure the acceptability of inaccessible areas (e.g., portions of supports encased in concrete, buried underground, or encapsulated by guard pipe) will be evaluated when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.
3. Ensure the use of molybdenum disulfide (MoS_2) and other lubricants containing sulfur on structural bolting is prohibited.
4. Ensure preventive measures include, when replacement of bolting is required, using only bolting material that has actual measured yield strength less than 150 ksi (1,034 MPa) and for bolting replacement and maintenance activities use of proper selection of bolting material and lubricants, and appropriate installation torque or tension, as recommended in EPRI documents (e.g., EPRI NP-5067 dated 1990 and EPRI TR-104213 dated December 1995),

American Society for Testing and Materials (ASTM) standards, and American Institute of Steel Construction Specifications, as applicable.

5. Implementing procedures will be revised to ensure that if bolting within the scope of the program consists of ASTM A325 and/or ASTM A490 bolts (including respective equivalent twist-off type ASTM F1852 and/or ASTM F2280 bolts), the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” dated August 2014, will be used.
6. Ensure that parameters monitored or inspected include corrosion; cracking, deformation; misalignment of supports; missing, detached, or loosened support items; general structural condition of weld joints and weld connection to building structure for loss of integrity; improper clearances of guides and stops; and improper hot or cold settings of spring supports, and constant load supports.
7. Implementing procedures will be revised to ensure: accessible areas of sliding surfaces will be monitored for debris, dirt, or indications of excessive loss of material due to wear that could prevent or restrict sliding as intended in the design basis of the support; elastomeric or polymeric vibration isolation elements will be monitored for cracking, loss of material, and hardening; and bolting will be monitored for corrosion, loss of integrity of bolted connections due to self-loosening, and material conditions that can affect structural integrity.
8. Implementing procedures will be revised to ensure that high strength bolting [actual measured yield strength greater than or equal to 150 ksi (1,034 MPa)] in sizes greater than 1 inch nominal diameter (including ASTM A490 bolts and ASTM F2280 bolts), will be monitored for SCC.
9. Implementing procedures will be revised to ensure that the provisions of ASME Code, Section XI, 2007 Edition, 2008 Addenda, Subsection IWF are supplemented to include 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. The one-time inspection will be conducted within 5 years prior to entering the subsequent period of extended operation. The additional supports will be selected from the remaining population of IWF piping supports. However, the responsible engineer should ensure that the sample includes components that are most susceptible to age-related degradation (i.e., based on time in service, aggressive environment, etc.).
10. Ensure that the extent, frequency, and examination methods are designed to detect, evaluate, or repair age-related degradation before there is a loss of component support intended function. The VT-3 examination method specified by the program will be used to reveal loss of material due to corrosion and wear, cracks, verification of clearances, settings, physical displacements, loose or missing parts, debris or dirt in accessible areas of the sliding surfaces, or loss of integrity at bolted connections.
11. Implementing procedures will be revised to ensure: the VT-3 examination method specified by the program will be used to can also detect loss of material and cracking of elastomeric or polymeric vibration isolation elements; tactile inspection (feeling) of elastomeric or polymeric vibration isolation elements will be used to detect hardening if the vibration isolation function is suspect; and visual examinations that detect surface flaws which exceed acceptance criteria will be supplemented, in accordance with IWF-3200, by either surface or volumetric examinations to determine the character of the flaw.
12. Implementing procedures will be revised to ensure that for all high-strength bolting [actual measured yield strength greater than or equal to 150 ksi (1,034 MPa)] in sizes greater than 1 inch nominal diameter (including ASTM A490 and equivalent ASTM F2280), volumetric

examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1 will be performed at least once per interval 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 of high-strength bolts greater than 1 inch nominal diameter subject to volumetric examination will consist of 20% of the population (for a material/environment combination) up to a maximum of 25 bolts per unit.

13. Implementing procedures will be revised to ensure that if a component support does not exceed the acceptance standards of IWF-3400 but is repaired to as-new condition, the sample will be increased or modified to include another support that is representative of the remaining population of supports that were not repaired.

14. Ensure the following conditions are identified as unacceptable in accordance with IWF-3410(a):

    - Loss of material, cracking, and hardening of elastomeric or polymeric vibration isolation elements that could reduce the vibration isolation function.

    The above conditions may be allowed to be accepted provided the technical basis for their acceptance is documented.

15. Ensure that identification of unacceptable conditions triggers an expansion of the inspection scope, in accordance with IWF-2430, and reexamination of the supports requiring corrective actions during the next inspection period, in accordance with IWF-2420(b). Additionally, in accordance with IWF-3122, ensure supports containing unacceptable conditions will be evaluated or tested or corrected before returning to service. Ensure corrective actions will be as delineated in IWF-3122.2. An alternative for evaluation or testing to substantiate structural integrity and/or functionality in accordance with IWF-3122.3 may also be used.

These program enhancements will be implemented no later than six months prior to the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.

A.2.1.31 10 CFR Part 50, Appendix J

The BFN 10 CFR 50 Appendix J aging management program is an existing condition monitoring program that consists of monitoring leakage rates through the containment system, its shell, 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. Consistent with the current licensing basis, the containment leak rate tests are performed in accordance with the regulations and guidance provided in 10 CFR Part 50 Appendix J, Option B, NEI 94-01, Revision 2-A and Revision 3-A, “Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J,” and subject to the requirements of 10 CFR Part 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants.” Additionally, 10 CFR Part 50, Appendix J requires a general visual inspection of the accessible interior and exterior surfaces of the containment structure and components to be performed prior to any Type A test and at periodic intervals between tests based on performance of the containment system.

A.2.1.32 Masonry Walls

The BFN Masonry Walls aging management program is an existing condition monitoring program and includes all masonry walls identified as performing intended functions in accordance with 10 CFR 54.4. The Masonry Wall program is based on guidance provided in NRC Inspection and Enforcement (IE) Bulletin 80-11, “Masonry Wall Design,” and NRC Information Notice 87-67, “Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11.”

The program manages inspections of masonry walls for loss of material and cracking, and increases in gaps between the masonry wall supports and the masonry walls that could impact the intended function or potentially invalidate its evaluation basis. The program relies on periodic visual inspections, conducted at a frequency not to exceed five years, to monitor and maintain the condition of masonry walls within the scope of subsequent license renewal so that the established evaluation basis for each masonry wall remains valid during the subsequent period of extended operation.

The objective of the program is to manage aging effects of loss of material and cracking of masonry units and mortar, and increases in gaps between the masonry wall supports and the masonry walls that could impact the intended function or potentially invalidate its evaluation basis. Conditions found to be “acceptable with deficiencies” or deemed to be “unacceptable” are documented and entered into the Corrective Action Program for evaluation, which results in analysis, repair, or replacement, as necessary. Nonsafety-related masonry walls, with a structural intended function in structures that are in-scope for subsequent license renewal, are also inspected as part of the Masonry Walls program. Masonry walls that are considered fire barriers are also managed by the Fire Protection program (A.2.1.15). Steel bracing, reinforcing and supports that are part of the masonry wall design are managed by the Structures Monitoring program (A.2.1.33).

The Masonry Walls aging management program will be enhanced as follows:

1. Revise implementing procedures to address specific primary parameter monitored of cracking or loss of material at the mortar joints and gaps between the supports and masonry walls.
2. Revise implementing procedures to require inspection results to be documented and compared to previous inspections to identify changes or trends in the condition of masonry walls.
3. Revise implementing procedures to require identified degradation, where practical, to be projected until the next scheduled inspection.
4. Revise implementing procedures to require results to be evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation.
5. Revise implementing procedures to ensure crack widths and lengths, and gaps between supports and masonry walls, that approach or exceed acceptance criteria are measured and assessed for trends.
6. Revise implementing procedures to encourage the use of photographs or surveys and to indicate photographic records may be used to document and trend the type, severity, extent and progression of degradation.

7. Revise implementing procedures to require each masonry wall that has observed degradation (e.g., shrinkage and/or separation, cracking of masonry walls, cracking or loss of material at the mortar joints and gaps between the supports and masonry walls) to be assessed against the evaluation basis to confirm that the degradation has not invalidated the original evaluation assumptions or impacted the capability to perform the intended functions.
8. Revise implementing procedures to require further evaluation to be conducted to determine if corrective action is required when the degradation is determined to impact the intended function of the wall or invalidate its evaluation basis.
9. Revise implementing procedures to require degraded conditions that exceed acceptance criteria and are accepted without repair or other corrective actions are technically justified or supported by an engineering evaluation.
10. Revise implementing procedures to adjust inspection frequencies, as determined by the Corrective Action Program, If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection.

These program enhancements will be implemented no later than six months prior to the subsequent period of extended operation.

A.2.1.33 Structures Monitoring

The BFN Structures Monitoring program is an existing condition monitoring program that consists of periodic visual inspection and monitoring of the condition of concrete and steel structures, structural components, component supports, and structural commodities to ensure that aging degradation (such as those described in American Concrete Institute (ACI) 349.3R-02, ACI 201.1R-08, Structural Engineering Institute/American Society of Civil Engineers (SEI/ASCE) 11-99, and other documents) will be detected, the extent of degradation determined and evaluated, and corrective actions taken prior to loss of intended functions. Structures and structural commodities are monitored on an interval not to exceed five years. The program also includes periodic evaluation of ground water chemistry and opportunistic inspections for the condition of below grade concrete. Quantitative results (measurements) and qualitative information from periodic inspections are trended with sufficient detail, such as photographs and surveys for the type, severity, extent, and progression of degradation, to ensure that corrective actions can be taken prior to a loss of intended function. The acceptance criteria are derived from applicable consensus codes and standards. For concrete structures, the program includes personnel qualifications and quantitative acceptance criteria of ACI 349.3R.

The Structures Monitoring aging management program will be enhanced as follows:

1. Revise implementing procedures to add the following structures to the scope:
    - Discharge Control Structure
    - Circulating Water Conduit
    - Low Level Radwaste (LLRW) Storage Facility
    - Supplemental Diesel Generator Building
    - Nitrogen Storage Tank Foundation
    - Radwaste/Condensate Water Storage Tanks Tunnels
    - Yard Structures, General

- Structural Commodities: Hazard Barriers and Elastomers; Miscellaneous Steel;and Penetrations and Sleeves

2. 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, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, "Specification for Structural Joints Using High-Strength Bolts," dated August 2014, will be used.
3. Revise implementing procedures to be consistent with ACI 349.3R-02 and SEI/ASCE 11-99 for selection of parameters to be monitored or inspected for concrete and steel structural elements and for steel liners, joints, coatings, and waterproofing membranes.
4. Ensure inspections include the following indicators to identify cracking due to expansion from reaction with aggregates:
   - Surface aggregate popouts
   - Pattern cracking with darkened crack edges
   - Water ingress
   - Misalignment Inspections
5. Revise implementing procedures to ensure steel, aluminum, and non-ferrous material components are monitored for cracking, loss of material due to corrosion or mechanical wear, and general degradation.
6. Revise implementing procedures to ensure accessible sliding surfaces will be monitored for indication of significant loss of material due to wear or corrosion, and for accumulation of debris or dirt.
7. Revise implementing procedures to ensure elastomeric vibration isolators, membranes, structural sealants, and seismic joint fillers are monitored for cracking, loss of material, hardening, separation and leakage.
8. Revise implementing procedures to include monitoring for earth berms for loss of material and loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, and seepage.
9. Revise implementing procedures to include monitoring of ground water chemistry for pH, chlorides, and sulfates on a frequency not to exceed five years that accounts for seasonal variances from locations that are representative of the groundwater in contact with the structures within the scope of this aging management program. Adverse results will be entered into the Corrective Action Program.
10. Revise implementing procedures to monitor and trend for signs of concrete or steel reinforcement degradation if through-wall leakage or groundwater infiltration is identified.
11. Revise implementing procedures that inspection of concrete structures, qualifications of inspection and evaluation personnel will be in accordance with ACI 349.3R-02.
12. Revise implementing procedures to require indications of groundwater infiltration or through-concrete leakage to be assessed for aging effects. This may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels. When leakage volumes allow, assessments may include analysis of the leakage pH, along with mineral, chloride, sulfate,

and iron content in the water. The responsible engineer for this program will also evaluate groundwater chemistry results that are sampled from locations representative of the water in contact with structures within the scope of subsequent license renewal.

13. Revise implementing procedures to state visual inspections may need to be enhanced or supplemented with nondestructive examination, destructive testing and/or analytical methods, based on the conditions observed or the parameter being monitored.
14. Revise implementing procedures to require visual inspection of elastomeric elements to be supplemented by tactile inspection to detect hardening if the intended function is suspect.
15. Revise implementing procedures to require the acceptability of inaccessible areas to be evaluated when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. The acceptability of inaccessible areas will also be assessed by examining representative samples of exposed portions of below grade concrete, when excavated for any reason.
16. Revise implementing procedures to establish quantitative baseline inspection data for structures and structural commodities for which baseline inspection data has not been established or for which the baseline acceptance criteria used are not comparable to the GALL-SLR acceptance criteria, prior to the subsequent period of extended operation.
17. Revise implementing procedures to require quantitative measurements and qualitative information to be recorded and trended for findings that exceed the acceptance criteria for all applicable parameters monitored or inspected.
18. Ensure acceptance criteria for each structure and aging effect that are derived from BFN design basis documents, applicable codes and standards that include but are not limited to ACI 349.3R-02, SEI/ASCE 11-99, or relevant AISC specifications and consider industry and plant operating experience.
19. Revise implementing procedures to ensure no evidence of popouts, map and pattern cracking with darkened crack edges, water ingress, and/or misalignment inspections; any evidence of these will require an engineering evaluation.
20. Revise implementing procedures to ensure no significant cracking, no significant loss of material due to corrosion or mechanical wear, and no significant signs of general degradation for steel, aluminum, and non-ferrous material components.
21. Revise implementing procedures to note loose bolts and nuts are not acceptable unless accepted by engineering evaluation for structural components within this aging management program.
22. Revise implementing procedures to add following acceptance criteria for structural steel bracing and edge supports associated with masonry block walls:
    - No adverse or significant deflection or distortion
    - No loose bolts (unless accepted by engineering evaluation)
23. Revise implementing procedures to require no signs of distress that could indicate degradation of the underlying material for painted or coated areas.
24. Revise implementing procedures to ensure there are no indications of excessive loss of material due to corrosion or wear and no debris or dirt that could restrict or prevent sliding of the surfaces as required by design.
25. Revise implementing procedures to ensure inspections for elastomeric vibration isolators, membranes, structural sealants, and seismic joint fillers the following acceptance criteria are met:

- Elastomeric membranes, structural sealants, and seismic joint fillers are acceptable if the observed loss of material, cracking, hardening, separation, and/or leakage will not result in the loss of sealing.
- Elastomeric vibration isolation elements are acceptable if there is no loss of material, cracking, hardening, separation, and/or leakage that could lead to the reduction or loss of isolation function.

26. Revise implementing procedures to add following acceptance criteria for earth berms:
    - No significant loss of material
    - No significant loss of form
    - No evidence of erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, or seepage that could lead to a loss of material or form.
27. Revise implementing procedures to ensure the groundwater chemistry has been determined to be within the following parameters: pH > 5.5, chlorides < 500 ppm, and sulfates <1,500 ppm. Groundwater chemistry values indicative of aggressive groundwater/ soil (pH < 5.5, chlorides > 500 ppm, or sulfates > 1,500 ppm) will be assessed for impact on concrete structural elements. This may include evaluations, destructive testing, and/or focused inspections of representative accessible (leading indicator) or below-grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil, on an interval not to exceed five years.

These program enhancements will be implemented no later than six months prior to the subsequent period of extended operation. Baseline inspections that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.

A.2.1.34 Inspection of Water-Control Structures Associated with Nuclear Power Plants

The BFN Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program is an existing condition monitoring program that consists of inspection and surveillances of raw water-control structures associated with emergency cooling systems and/or flood protection to identify aging effects prior to loss of intended functions. The program also includes requirements for structural steel and structural bolting associated with water-control structures.

The program addresses age-related deterioration, degradation due to environmental conditions, and the effects of natural phenomena that may affect the intended design basis functions of water-control structures and components within the scope of the program. The program recognizes the importance of periodic monitoring and maintenance of water-control structures so that the consequences of age-related deterioration and degradation can be prevented or mitigated in a timely manner. The monitoring methods described in the program are effective in detecting aging effects and the frequency of the monitoring is sufficient to prevent the loss of the intended design functions due to age related degradation.

NRC Regulatory Guide 1.127 Revision 2, Positions C.1 through C.10 delineates current NRC practice in evaluating inspection programs for water-control structures. BFN does not commit to this regulatory guide. The program however, does incorporate the detailed guidance in accordance with NRC Regulatory Guide 1.127, Revision 2, Positions C.1 through C.10 for the inspection programs and surveillances for water-control structures, including guidance on quantitative measurements, acceptance criterion, parameters monitored, engineering data compilation, inspection activities, technical evaluation, inspection frequency, special inspections, and the content of inspection reports. Inspections will occur at least once every five years.

The Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program will be enhanced as follows:

1. Revise implementing procedures to add Circulating Water Conduits to the scope of the program.
2. Ensure preventive actions are included 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, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” dated August 2014, will be used.
3. Revise implementing procedures for monitoring and inspection of water-control concrete structures to also include those parameters as described in ACI 201.1R, these include cracking, movements (e.g., settlement, heaving, and deflection), conditions at junctions with abutments and embankments, loss of material, increase in porosity and permeability, seepage, and leakage.
4. Revise implementing procedure to also include monitoring of the cool water and intake channels for sedimentation, debris, or instability of slopes that may impair the function of the canals under extreme low flow conditions.
5. Revise implementing procedure to include examinations of painted or coated areas for signs of distress that could indicate degradation of the underlying material.
6. Revise implementing procedure to include monitoring of bolting within the scope of the program for loss of material, loose bolts, missing or loose nuts, and other conditions indicative of loss of preload. In addition, concrete around anchor bolts is monitored for cracking.
7. Revise implementing procedures to examine representative samples of the exposed portions of the below-grade concrete when excavated for any reason. The acceptability of inaccessible areas will be evaluated when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.
8. Revise implementing procedures to ensure indications of groundwater infiltration or through-concrete leakage are assessed for aging effects. This may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels. When leakage volumes allow, assessments may include analysis of the leakage pH, along with mineral, chloride, sulfate and iron content in the water.
9. Revise implementing procedures to ensure submerged areas are monitored for indication of degradation with periodic inspections performed at intervals in accordance with the guidance in NRC Regulatory Guide 1.127 Revision 2. Submerged concrete structures may be inspected during periods of low tide, when dewatered, or with divers.
10. Ensure NRC Information Notice 2011-20, “Concrete Degradation by Alkali-Silica Reaction (ASR),” is referenced and add additional guidance for concrete inspections to identify indications of the presence of ASR. The additional guidance for these inspections of

reinforced concrete, each inspection interval, include examination for pattern cracking with darkened crack edges, water ingress, and misalignment inspections. These inspection results will be evaluated by the responsible engineer each inspection cycle to identify changes that could be indicative of aging effects caused by reaction with aggregates. Such indications will be entered into the Corrective Action Program for evaluation.

11. Ensure the guidance of NRC Regulatory Guide 1.127 Revision 2, for the compilation of engineering data collected from aging management program inspections is included. The use of photographs and surveys for comparison purposes of previous and current conditions as well as review of previous inspection records (baseline) may be used to identify new or progressive issues. Collected engineering data is reviewed by qualified engineering personnel to determine if changes fall outside the normal or expected conditions.
12. Ensure trending of quantitative measurements and qualitative information is required for findings exceeding acceptance criteria for applicable parameters monitored or inspected.
13. Revise implementing procedures to require quantitative baseline inspection data to be established in accordance with acceptance criteria prior to the subsequent period of extended operation. Previously performed inspections that were conducted using comparable acceptance criteria will be acceptable in lieu of performing a new baseline inspection.
14. Revise implementing procedures to require an engineering evaluation or the initiation of a Condition Report in the Corrective Action Program when any structural condition (including loose bolts, nuts, and degradation of piles and sheeting) is classified as “acceptable with deficiencies” or “unacceptable.”
15. Ensure acceptance criteria for inspections of earthen structures and canals shall ensure no significant loss of material or loss of form or evidence of erosion, settlement, frost action, waves, currents, surface runoff, or seepage, and ensure intake channel sedimentation is within design basis values.

These program enhancements will be implemented no later than six months prior to the subsequent period of extended operation. Baseline inspections that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.

A.2.1.35 Protective Coating Monitoring and Maintenance

The BFN Protective Coating Monitoring and Maintenance aging management program is a new program that ensures monitoring and maintenance of Service Level 1 coatings are implemented in accordance with Position C.4 of NRC Regulatory Guide 1.54, “Service Level I, II, IIII, and In-Scope License Renewal Protective Coatings Applied to Nuclear Power Plants,” Revision 3, for the subsequent period of extended operation. The program consists of guidance for selection, application, inspection, and maintenance of protective coatings. The program will use the aging management detection methods, inspector qualifications, inspection frequency, monitoring, trending, and acceptance criteria defined in ASTM D 5163-08, “Standard Guide for Establishing a Program for Condition Assessment of Coating Service Level I Coating Systems in Nuclear Power Plants.” The program addresses coatings applied to steel and concrete surfaces inside containment. These coatings are not credited for managing the effects of corrosion for the carbon steel containment shells 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 (ECCS) suction strainers. Degraded coatings in the containment are assessed periodically to ensure post-accident operability of the ECCS.

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.

This new program will be implemented no later than six months prior to the subsequent period of extended operation.

A.2.1.36 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The BFN Electrical Insulation for Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is an existing condition monitoring program that manages the effects of reduced insulation resistance of the electrical insulation for subsequent license renewal in-scope, non-environmentally qualified, electrical cables and connections during the subsequent period of extended operation.

Accessible cables and connections located in adverse localized environments are managed by visual inspection. These cables and connections are visually inspected at least once every 10 years for cable jacket and connection insulation surface anomalies, such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination that could indicate incipient conductor insulation aging degradation from temperature, radiation, or moisture.

Age-related degradation observed during the inspection process is addressed by the initiation of a Condition Report in accordance with the Corrective Action Program. If an unacceptable condition or situation is identified for a cable or connection in the inspection sample, an evaluation will determine if the same condition or situation is applicable to other accessible or inaccessible cables or connections. Additional inspections, repairs, or replacements are initiated as appropriate under the Corrective Action Program. If visual inspections identify degraded or damaged conditions that may impact the cable system's ability to perform its intended functions, then testing may be performed for evaluation. Testing may include thermography and one or more proven condition monitoring test methods applicable to the cable and connection insulation material. Testing as part of an existing maintenance, calibration or surveillance program may be credited. Electrical cable and connection insulation material test results are to be within the acceptance criteria, as identified in BFN procedures.

The Electrical Insulation for Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be enhanced as follows:

1. Revise the implementing procedures to require review of plant-specific OE for previously identified and mitigated adverse localized environments cumulative aging effects applicable to in-scope cable and connection electrical insulation.
2. Revise the implementing procedures to require inspections for adverse localized environments for each of the most limiting cable and connection electrical insulation plant environments (e.g., caused by temperature, radiation, moisture, or contamination).

3. Revise the implementing procedures to require, during inspections, that cable and connection insulation be evaluated to confirm that aging related dispositioned corrective actions continue to support in-scope cable and connection intended functions during the subsequent period of extended operation.
4. Revise the implementing procedures to require the first inspection for subsequent license renewal to be completed prior to the subsequent period of operation.
5. Revise the implementing procedures to require that If visual inspections identify degraded or damaged conditions , then testing may be performed for evaluation. For a large number of cables and connections identified as potentially degraded, a sample population is tested. The factors to be considered in the development of the cable and connection insulation sample representing approximately 20% of the in-scope population include: environment including identified adverse localized environments (high temperature, high humidity, vibration, etc.), voltage level, circuit loading, connection type, location, and insulation material. Additionally, the component sampling methodology will utilize a population that includes a representative sample of in-scope electrical cable and connection types regardless of whether or not the component was included in a previous aging management or maintenance program. The technical basis for the sample selection will be required to be documented.
6. Revise the implementing procedures to ensure acceptance criteria are met by conducting a review of test results or findings of surveillances of in-scope components.
7. Revise the implementing procedures to allow cable system testing, in accordance with applicable TVA procedures, as an alternative means for testing if visual inspections does not meet acceptance criteria.
8. Revise the implementing procedures to require, when an unacceptable condition is identified, an evaluation to be performed to demonstrate that the condition will not adversely affect the affected component's ability to perform it's associated intended function for the time period being considered. The evaluation, including the technical basis, shall be documented.
9. Revise the implementing procedures to require a determination as to whether the same condition or situation is applicable to additional in-scope accessible and inaccessible cables or connections (extent of condition).

The program will be enhanced no later than six months prior to the subsequent period of extended operation. Inspections and tests that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.

A.2.1.37 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits

The BFN Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits aging management program is an existing performance monitoring program that manages the effects of reduced insulation resistance of non-environmentally qualified cable and connection electrical insulation in instrumentation circuits with sensitive, high-voltage, low-level current signals. The program applies to the in-scope portions of the Neutron Monitoring System and the Radiation Monitoring System (not managed by the Environmental Qualification of Electrical Equipment program (A.3.1.3)) that are subjected to adverse localized environments caused by temperature, radiation, or moisture.

This program requires that specific calibration, surveillances, or testing be performed. This testing verifies the material condition of electrical insulation used in instrumentation cables and connections located in adverse localized environments that are within the scope of subsequent license renewal.

BFN performs reviews of calibration results or findings of surveillance programs to ensure that tested components can perform their intended functions and to provide early indication of age related degradation that may adversely impact performance prior to loss of function.

Calibration, surveillance, and testing results that do not meet acceptance criteria are entered into the Corrective Action Program for evaluation and resolution and are reviewed for aging effects when the results are available. The first reviews of calibration, surveillance, and testing results will be completed prior to the subsequent period of extended operation and at least every 10 years thereafter.

Age-related degradation observed during calibration, surveillance, or testing is addressed by the initiation of a Condition Report in accordance with the Corrective Action Program. If an unacceptable condition or situation is identified for a cable or connection, an evaluation will determine if the same condition or situation is applicable to other similar cables or connections. Additional testing, repairs, or replacements are initiated as appropriate under the Corrective Action Program. Testing may include one or more proven condition monitoring test methods applicable to the cable and connection insulation material. Electrical cable and connection insulation material test results are to be within acceptance criteria, as identified in BFN procedures.

The Electrical Insulation for Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits aging management program will be enhanced as follows:

1. Revise the implementing procedures to include the in-scope portions of the Radiation Monitoring System listed in BFN SLRA subsection 2.3.3.37.
2. Revise implementing procedures to include documented reviews of plant-specific OE for previously identified and mitigated adverse localized environments cumulative aging effects applicable to in-scope cable and connection electrical insulation.
3. Revise implementing procedures to include documented inspections for adverse localized environments for each of the most limiting cable and connection electrical insulation plant environments (e.g., caused by temperature, radiation, moisture, or contamination).
4. Revise the implementing procedures to include documentation of reviews of calibration, surveillance, and test results for the components within the scope of the program.
5. Revise the implementing procedures to include performance of cable tests for the components within the scope of the program when the calibration or surveillance program does not include the cabling system in the testing circuit, or as an alternative to the review of calibration results.
6. Revise implementing procedures to require trending of inspection and test results that are trendable and provide additional information on the rate of cable or connection degradation when age related degradation is suspected or found.

7. Revise implementing procedures to ensure acceptance criteria are met by conducting a review of calibration results or findings of surveillances of in-scope components prior to the subsequent period of extended operation and at least once every 10 years.
8. Revise implementing procedures to allow cable system testing, in accordance with applicable TVA procedures, as an alternative means for testing if there is cable degradation when a calibration does not meet acceptance criteria.

The program will be enhanced no later than six months prior to the subsequent period of extended operation. Reviews and tests that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.

A.2.1.38 Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The BFN Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is an existing condition monitoring program that will provide reasonable assurance that the intended functions of inaccessible medium-voltage power cables (operating voltages of 2 kV to 35 kV) that are not subject to the environmental qualification requirements of 10 CFR 50.49 are maintained consistent with the current licensing basis through the subsequent period of extended operation. This program applies to all inaccessible or underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) medium-voltage cables that are within the scope of subsequent license renewal and potentially exposed to wetting or submergence (i.e., significant moisture). Inaccessible medium-voltage cables designed for continuous wetting or submergence are also included in this program for a one-time inspection and test.

Periodic inspections are conducted to prevent inaccessible medium-voltage power cables from being exposed to significant moisture. Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period) that, if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that results from event driven occurrences and is mitigated by either automatic or passive drains is not considered significant moisture for this program.

The inspection frequency for water accumulation is established and performed based on plant-specific operating experience (OE) over time with cable wetting or submergence. Inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually with the first inspection for subsequent license renewal completed prior to the subsequent period of extended operation. Inspection frequencies are adjusted based on inspection results including plant-specific OE but with a minimum inspection frequency of at least once annually.

Inspections for water accumulation are also performed after event driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding. Plant-specific parameters are established for the initiation of an event driven inspection. Inspections include direct indication that cables are not wetted or submerged, and that cable/splices and cable support structures are intact.

Dewatering systems (e.g., sump pumps and passive drains) are inspected, and their operation verified periodically. The periodic inspection includes documentation that either automatic or passive drainage systems or manually pumping are effective in preventing cable exposure to significant moisture. Cable testing and manhole inspection results that do not meet the acceptance criteria are evaluated in the Corrective Action Program.

In addition to the above periodic actions, in-scope inaccessible medium-voltage power cables exposed to significant moisture are tested to determine the condition of the electrical insulation. One or more tests may be required based on cable application, construction, and electrical insulation material to determine the age-related degradation of the cable. The first tests will be completed prior to the second period of extended operation. The cables will be tested at least once every six years thereafter. More frequent testing may occur based on test results and operating experience.

The Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be enhanced as follows:

1. Revise implementing procedures to specifically include splices present in medium-voltage cables in the scope of this aging management program.
2. Revise implementing procedures to require the performance of a one-time inspection and test of submarine or other cables designed for continuous wetting or submergence. Additional periodic tests and inspections for these cables will be determined by the one-time test/inspection results as well as industry and plant-specific OE.
3. Revise implementing procedures to require the inspection frequency for water accumulation to be established and adjusted based on plant-specific OE with cable wetting or submergence.
4. Revise implementing procedures to require the inspections for water accumulation to be performed after event driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding.
5. Revise implementing procedures to require dewatering systems (e.g., sump pumps and passive drains to be inspected and their operation verified periodically (annually). The periodic inspection will include documentation that either automatic or passive drainage systems or manually pumping are effective in preventing cable exposure to significant moisture.
6. Revise implementing procedures to require that if water is found during inspection for water accumulation, the condition will be entered in the Corrective Action Program. The Corrective Action Program will specify and document the completion of actions taken to keep the cables free from significant moisture and to assess cable degradation.
7. Revise implementing procedures to require the first cable tests to be completed prior to the subsequent period of extended operation with additional tests to be performed at least once every six years thereafter.
8. Revise implementing procedures to require a BFN-specific inaccessible medium-voltage cable test matrix that documents inspection methods, test methods, and acceptance criteria for in-scope inaccessible medium-voltage power cables to be developed based on OE.
9. Revise implementing procedures to require visual inspections to be performed each time with the same inspection requirements (i.e., location, the manner inspected, etc.) such that the results can be compared to previous results for both immediate condition and long-term trend determinations.

10. Revise implementing procedures to require test results and associated trends to be evaluated against acceptance criteria to confirm that the timing of subsequent inspections and testing will maintain the components' intended functions throughout subsequent period of extended operation based on the projected rate of degradation.

The program will be enhanced no later than six months prior to the subsequent period of extended operation. Inspections and tests that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.

A.2.1.39 Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The BFN Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is a new condition monitoring program.

This program applies to inaccessible or underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) instrumentation and control cables that are within the scope of subsequent license renewal and potentially exposed to significant moisture.

In this program, periodic actions will be taken to prevent inaccessible instrumentation and control cables from being exposed to significant moisture including inspecting for water accumulation in cable manholes, vaults, conduits, and removing water, as needed. Instrumentation and control cables accessible from manholes, vaults, or other underground raceways will be visually inspected for cable surface abnormalities. Visual inspection frequency will be established and adjusted based on inspection and test results as well as plant-specific and industry Operating Experience (OE). For inaccessible and underground instrumentation and control cables exposed to significant moisture where testing is required, a one-time test will be performed. Visual inspections will occur at least once every six years and may be coordinated with the periodic inspection for water accumulation. The periodic inspections for water will occur at least once annually with the first inspection for subsequent license renewal completed prior to the subsequent period of extended operation. Inspections for water accumulation will also be performed after event-driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding.

In addition to the previously stated actions and inspections mentioned, in-scope instrumentation and control cables subject to significant moisture will be evaluated to determine whether a periodic or one-time test is needed for condition monitoring of the cable insulation system. Initial test will be performed once on a sample population to determine the condition of the electrical insulation. Samples of 20 percent with a maximum of 25 constitute a representative cable sample size. The sample used and the basis for the methodology will all be documented.

Testing of installed in-service inaccessible and underground instrumentation and control cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible medium- or low-voltage power cables subjected to the same or bounding 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 instrumentation and control cables when testing is recommended in this program.

Dewatering systems (e.g., sump pumps and passive drains) will be inspected, and their operation verified periodically. The periodic inspection will include documentation that either automatic or passive drainage systems or manually pumping are effective in preventing cable exposure to significant moisture. Cable testing and manhole inspection results that do not meet the acceptance criteria will be evaluated in the Corrective Action Program.

This new program will be implemented no later than six months prior to the subsequent period of extended operation. One-time cable testing, initial manhole inspections, and initial visual cable inspections will be completed no later than 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.

A.2.1.40 Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The BFN Electrical Insulation for Inaccessible Low Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is a new condition monitoring program. Power cables that typically operate at a voltage of less than 1,000V, but no greater than 2kV, and are not subject to the environmental qualification (EQ) requirements of 10 CFR 50.49 are in-scope for this program.

All in-scope power cables that are inaccessible or underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) and are potentially exposed to significant moisture are covered by this program. This program also includes in-scope power cables that are designed for continuous wetting or submergence.

Periodic actions will be taken to prevent in-scope power cables from being exposed to significant moisture. Inspecting for water accumulation in cable manholes and removing the water as needed is an example of actions that will be taken. In-scope power cables that are accessible from manholes, vaults, or other underground raceways will be visually inspected for cable insulation abnormalities.

The visual inspection frequency for water accumulation in manholes/vaults will be established and adjusted based on plant-specific Operating Experience (OE) with cable wetting or submergence as well as inspection and test results. For inaccessible and underground low-voltage power cables exposed to significant moisture where testing is required, a one-time test will be performed. Visual inspections will occur at least once every six years and may be coordinated with the periodic inspection for water accumulation. The periodic inspections for water will occur at least once annually with the first inspection for subsequent license renewal completed prior to the subsequent period of extended operation. Inspections for water accumulation will also be performed after event-driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding.

In addition to the previously stated actions and inspections mentioned, in-scope power cables subject to significant moisture will be evaluated to determine whether a periodic or one-time test is needed for condition monitoring of the cable insulation system. Initial test will be performed once on a sample population to determine the condition of the electrical insulation. Samples of

20 percent with a maximum of 25 constitute a representative cable sample size. The sample used and the basis for the methodology will all be documented.

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 low-voltage power cables subjected to the same or bounding 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 in this program.

Dewatering systems (e.g., sump pumps and passive drains) will be inspected, and their operation verified periodically. The periodic inspection will include documentation that either automatic or passive drainage systems or manually pumping are effective in preventing cable exposure to significant moisture. Cable testing and manhole inspection results that do not meet the acceptance criteria will be evaluated in the Corrective Action Program.

This new program will be implemented no later than six months prior to the subsequent period of extended operation. One-time cable testing, initial manhole inspections, and initial visual cable inspections will be completed no later than 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.

A.2.1.41 Metal Enclosed Bus

The BFN Metal Enclosed Bus aging management program is an existing condition monitoring program and no actions are taken as part of this program to prevent or mitigate aging degradation. The program applies to metal enclosed buses within the scope of subsequent license renewal to identify age-related degradation of electrical insulating material (i.e., thermoplastic organic polymers), metallic, and elastomer components (e.g., gaskets, boots, and sealants). The program manages the effects of in-scope electrical bus portions of isolated and non-segregated phase bus associated with the Station Blackout path during the subsequent period of extended operation.

Metal Enclosed Bus internal surfaces are visually inspected for aging degradation including cracks, corrosion, foreign materials debris, excessive dust buildup, and evidence of moisture intrusion. Metal Enclosed Bus insulating material is visually inspected for signs of embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination. Internal bus insulating supports are visually inspected for structural integrity and signs of cracks. 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 or loss of strength. Both thermography and visual inspections are used at BFN to show that electrical insulating material, metallic, and elastomer components are free from the unacceptable aging effects. The first inspection for measuring connection resistance or thermography is completed prior to the subsequent period of extended operation and every 10 years thereafter.

All unacceptable thermography and/or visual inspections shall be documented in the Corrective Action Program and subject to an engineering evaluation. When the acceptance criteria are not met to demonstrate that the Metal Enclosed Bus intended function can be maintained consistent with the current licensing basis, an engineering evaluation(s) is performed to demonstrate that the inaccessible Metal Enclosed Bus segments, together with the accessible Metal Enclosed Bus inspection and test program, will continue to maintain the Metal Enclosed Bus consistent with the current licensing basis during the subsequent period of extended operation.

The Metal Enclosed Bus aging management program will be enhanced as follows:

1. Revise implementing procedures to add the following to the scope of the program:
   - Start Bus 1A and 1B
   - Bus that connect the Unit Station Service Transformer 1A to the 4kV Common Board A
   - Bus between Start Bus 1A and 4kV Common Board A
   - Bus that connect the Unit Station Service Transformer 2A to the 4kV Common Board B
   - Bus between Start Bus 1B and 4kV Common Board B
2. Revise implementing procedures to require, for inaccessible Metal Enclosed Bus internal or external segments, documented engineering evaluation(s) to be performed to demonstrate that the inaccessible Metal Enclosed Bus segments evaluation, together with the accessible Metal Enclosed Bus inspection and test program, will continue to maintain the Metal Enclosed Buses consistent with the current licensing basis during the subsequent period of extended operation. These engineering evaluation(s) can be based on the results of accessible Metal Enclosed Bus inspections, tests, or other analyses.
3. Revise implementing procedures to require 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 or loss of strength.
4. Revise implementing procedures to require documented visual inspection of insulation material to detect surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination, when thermography or measuring connection resistance of accessible bolted connections covered with heat shrink tape, sleeving, insulating boots, etc., is not possible, to validate the absence of surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination.
5. Revise implementing procedures to require, when an alternative visual inspection is used to check Metal Enclosed Bus bolted connections, that the first inspection be completed prior to the subsequent period of extended operation and every five years thereafter.
6. Revise implementing procedures to require trending of inspection results that are trendable and provide additional information on the rate of degradation when age related degradation is suspected or found.
7. Revise implementing procedures to require all unacceptable thermography and/or visual inspections to be documented in a corrective action and subject to an engineering evaluation.
8. Revise implementing procedures to require that when an unacceptable condition or situation that is identified, (e.g., internal surface degradation including cracks, corrosion, foreign debris, excessive dust buildup, moisture intrusion, insulating material embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination), a determination to be made as to whether the same condition or situation is applicable to Metal Enclosed Bus bolted connections not inspected or tested. Further, when acceptance criteria are not met, a

determination will be made as to whether the surveillance, inspection, or test, including frequency intervals, needs to be modified.

These program enhancements will be implemented no later than six months prior to the subsequent period of extended operation. Inspections and tests that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.

A.2.1.42 Fuse Holders

The BFN Fuse Holders aging management program is a new condition monitoring program. The Fuse Holders program will apply to fuse holders outside of active equipment within the scope of subsequent license renewal and susceptible to the following aging effects: increased resistance of connection due to chemical contamination, corrosion, and oxidation or fatigue caused by ohmic heating, thermal cycling, electrical transients, frequent removal and replacement, or vibration. The program will also manage degradation of electrical insulation for the fuse holders with metallic clamps susceptible to the aging effects identified. Fuse holders inside an active device (e.g. switchgears, power supplies, inverters, battery chargers, and circuit boards) are not within the scope of this program.

The program will utilize thermography and visual inspection and testing to identify age-related degradation for both fuse holder electrical insulation material and fuse holder metallic clamps. The specific type of test performed will be determined prior to the initial test and is to be a proven test for detecting increased resistance of connection of fuse holder metallic clamps, or other appropriate testing justified in the Fuse Holders aging management program.

Industry and plant-specific OE will be considered in the development and implementation of this program.

The new program will be implemented no later than six months prior to the subsequent period of extended operation. Inspections and tests that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.

A.2.1.43 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

The BFN Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is a new condition monitoring program. Cable connections associated with cables within the scope of subsequent license renewal that are external connections terminating at active or passive devices, are in the scope of this program. Wiring connections internal to an active assembly are considered part of the active assembly and, therefore, are not within the scope of this program.

This program will implement one-time testing of the metallic parts of a representative sampling of cable connections within the scope of subsequent license renewal. The sample of cable connections within the scope of license renewal will be tested on a one-time test basis or periodically once every five years, if only visual inspection is used during the one-time test 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 10 years of initial testing. One-time testing will provide an indication of increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation. Representative samples of each type of electrical cable connection will be tested. The following factors will be considered for sampling: voltage level (medium and low-voltage), circuit loading (high load), connection type, and location (high temperature, high humidity, vibration, etc.). The technical basis for the sample selection will be documented.

Testing may include thermography, contact resistance testing, or other appropriate testing methods without removing the connection insulation. One-time testing provides additional confirmation to support industry OE that shows that electrical connections have not experienced a high degree of failures, and that existing installation and maintenance practices are effective. This one-time testing will also confirm that there are no aging effects requiring management during the subsequent period of extended operation. Twenty percent of a connector type population with a maximum sample of 25 constitutes a representative connector sample size.

The acceptance criteria will be specific for each type of test and the specific type of cable connections tested. Cable connections should not indicate abnormal temperatures when measured by thermography. Connections which cannot be adequately assessed by thermography will be assessed by contact resistance measurement or another appropriate test. When the visual inspection alternative for covered cable connections is used, the absence of embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination indicates that the covered cable connection components are not loose. Results that do not meet the acceptance criteria will be addressed in the Corrective Action Program. The findings of the initial one-time test will be evaluated to determine whether periodic testing of the cable connections is warranted. The justification and technical basis for not performing subsequent periodic testing will be documented.

The new program will be implemented no later than six months prior to the subsequent period of extended operation. Inspections and tests that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.

A.3.0 NUREG-2191 Chapter X Aging Management Programs

Aging Management Programs evaluated in Chapter X of NUREG-2191 are associated with Time-Limited Aging Analyses. These programs are evaluated in this section.

A.3.1.1 Fatigue Monitoring

The BFN Fatigue Monitoring aging management program is an existing program that manages fatigue damage of reactor vessel components, reactor coolant pressure boundary piping components, and other components. The program monitors and tracks the number of critical thermal, pressure, and seismic transients to ensure that the cumulative usage factor (CUF) and environmentally-assisted fatigue (CUF_{en}) for each analyzed component does not exceed the applicable limit through the subsequent period of extended operation. The program monitors and tracks the number and severity of thermal and pressure transients for BFN as specified In FSAR Section 4.2.5, which is referenced in Technical Specifications Section 5.5.5, Component Cyclic and Transient Limits. No BFN ANSI B31.1 and ASME Code Class 2 and 3 maximum allowable stress range reduction/expansion stress analyses have been dispositioned in accordance with 10 CFR 54.21(c)(1)(iii), therefore this program does not apply to these analyses. No ASME Section III fatigue waiver analyses have been dispositioned in accordance with 10 CFR 54.21(c)(1)(iii), therefore this program does not apply to fatigue waiver analyses. No cycle-based flaw growth, flaw tolerance, or fracture mechanics analyses that are based on cycle-based loading assumptions have been dispositioned in accordance with 10 CFR 54.21(c)(1)(iii), therefore this program does not apply to flaw growth; flaw tolerance, or fracture mechanics analyses. The program also monitors applicable design transient parameters (e.g., temperatures, pressures, displacements, strains, flow rates, etc.) for components with stress-based fatigue calculations.

The program utilizes the FatiguePro^{TM} software which is a computerized data acquisition, recording, and tracking program. FatiguePro^{TM} is used to determine the overall cumulative number of transient cycles that have occurred at a given time and determines the CUF values resulting from the combination of transient cycles that have occurred. The program monitors the environmental effects of reactor coolant on Class 1 components by using the guidance in NRC Regulatory Guide 1.207, Revision 1, applicable fatigue curves in NUREG/CR-6909, Revision 1, and calculated alternating stress values from the existing ASME Code fatigue calculations to determine CUF_{en} values. FatiguePro^{TM} performs “stress-based” and “cycle-based” fatigue monitoring.

The cumulative CUF and CUF_{en} values for the components monitored by FatiguePro^{TM} are compared to appropriate allowable limits (e.g., 1.0 for ASME Section III locations, or 1.0 for CUF_{en} for environmental fatigue locations). When a cumulative CUF or CUF_{en} value exceeds 70 percent of applicable allowable limit, corrective action is taken to review the applicable fatigue analyses and take appropriate actions to prevent exceeding the limit.

This program verifies the continued acceptability of existing fatigue analyses through transient cycle counting and calculation of cumulative CUF and CUF_{en} values to demonstrate that they continue to meet the appropriate limits. The program requires comparison of actual event parameters to the applicable design transient definitions to ensure the actual transient is bounded by the applicable design transient. CUF and CUF_{en} values are computed parameters used to assess the likelihood of fatigue damage. Fatigue crack initiation is assumed to begin in a mechanical or structural component when the CUF and CUF_{en} values reach the value of 1.0.

The Fatigue Monitoring aging management program will be enhanced to:

1. Revise implementing procedures to require monitoring of the Refueling Containment Skirt within the scope of the program.
2. Revise implementing procedures to require component locations that are in the scope of the program to be revised based on operating experience, plant modifications, and inspection findings.
3. Revise implementing procedures to ensure periodic review of chemistry parameters that give inputs to F_{en} factors used in CUF_{en} calculations for environmentally-assisted fatigue calculations.

4. Analysis has been completed to re-evaluate the cumulative fatigue limit for the recirculation inlet nozzle safe ends, and the limits will be revised in FatiguePro^{TM} prior to entry into the subsequent period of extended operation.
5. FatiguePro^{TM}, Version 4, will be implemented prior to entry into the subsequent period of extended operation.
6. Revise implementing procedures to provide for modifications to fatigue analyses or other corrective actions on an “as-needed” basis if assumed parameter values are approached, if transient severities exceed the design or assumed severities, if transient counts exceed the design or assumed quantities, if the definition of a transient is modified, if new transient events are identified, or if plant modifications to components change specified geometries.
7. Revise implementing procedures to reflect the re-evaluated cumulative fatigue values for the Units 1, 2, and 3 recirculation inlet nozzle safe ends.
8. Revise implementing procedures to require corrective actions for any locations projected to exceed a CUF or CUF_{en} of 1.0 during the subsequent period of extended operation, to include:
   - Repair or replacement of the component or
   - Provide a more rigorous analysis of the component to demonstrate that the CUF or CUF_{en} will not exceed 1.0 during the subsequent period of extended operation or
   - Perform a flaw tolerance analysis with appropriate (e.g., inclusion of environmental effects) crack growth rate curves and associated inspections performed in accordance with Appendix L of ASME Code Section XI.
9. Revise implementing procedures for CUF_{en} analyses projected to exceed a 1.0 during the subsequent period of extended operation, that scope expansion will included consideration of other locations with the highest expected CUF_{en} values.

These program enhancements will be implemented no later than six months prior to the subsequent period of extended operation.

A.3.1.2 Neutron Fluence Monitoring

The BFN Neutron Fluence Monitoring aging management program is a new condition monitoring program that monitors and tracks increasing neutron fluence (integrated, time-dependent neutron flux exposures) to reactor vessel and reactor vessel internal components to ensure that applicable reactor vessel neutron irradiation embrittlement analyses (i.e., TLAAs) and radiation-induced aging effect assessments for reactor internal components will remain within their applicable limits. The program manages loss of fracture toughness due to neutron irradiation embrittlement. The components evaluated by these analyses are the reactor vessel shell, welds, and nozzles in the extended beltline region and reactor vessel internal components subject to a reactor coolant and neutron flux environment which are fabricated from carbon or low alloy steel with stainless steel cladding, stainless steel, and nickel alloy materials.

The program verifies the continued acceptability of existing analyses through neutron fluence monitoring, assesses susceptibility of reactor vessel internal components to neutron irradiation-related damage, and determines and monitors the extent of the reactor vessel beltline region. Thus, the program ensures the analyses involving neutron fluence inputs continue to meet the appropriate limits defined in the CLB.

Monitoring is performed to verify the adequacy of neutron fluence projections, which are defined for the CLB in NRC approved reports. The methods and assumptions for projecting reactor vessel neutron fluence for the beltline region are consistent with NRC Regulatory Guide 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.” The methods and assumptions used for the original beltline region are considered appropriate for the beltline region that has been extended to encompass materials projected to experience fluence in excess of 1×10^{17} n/cm^2 (E >1 MeV) at the end of the subsequent period of extended operation, since the extended region does not extend significantly above or below the active fuel region and no additional reactor vessel plate materials (heat numbers) or welds are projected to experience fluence in excess of 1×10^{17} n/cm^2 (E > 1 MeV). The methods for projecting reactor vessel internal component fast neutron fluence values are not governed by specific regulatory guidance or requirements. In the absence of such regulatory guidance, the intent of NRC Regulatory Guide 1.190, particularly with regards to conservatism in constructing and evaluating reactor components, has been used in the determination of the fast neutron fluence throughout the reactor vessel.

The neutron fluence monitoring program results are compared to the neutron fluence parameter inputs used in the neutron embrittlement analyses for reactor vessel components. This includes but is not limited to the neutron fluence inputs for the reactor vessel upper-shelf energy analyses (or equivalent margin analyses) and P-T limits analyses that are required to be performed in accordance with 10 CFR Part 50, Appendix G requirements. Comparisons to the neutron fluence inputs for other analyses include those for reflood thermal shock analysis of the reactor vessel, reflood thermal shock analysis of the reactor vessel core shroud, reactor vessel thermal limit analysis (operating P-T limits), reactor vessel circumferential weld examination relief, reactor vessel axial weld failure probability, and aging effect assessments for BWR reactor internals that are induced by neutron irradiation exposure mechanisms.

Reactor vessel surveillance capsule dosimetry data obtained in accordance with 10 CFR Part 50, Appendix H, requirements, and through implementation of the Reactor Vessel Material Surveillance program (A.2.1.19), provide inputs to and have impacts on the neutron fluence monitoring results that are tracked by this program. In addition, regulatory requirements in the plant technical specifications or in specific regulations of 10 CFR Part 50 may apply, including those in 10 CFR Part 50, Appendix G and 10 CFR 50.55a.

The new program will be implemented no later than six months prior to the subsequent period of extended operation.

A.3.1.3 Environmental Qualification of Electric Equipment

The BFN Environmental Qualification of Electric Equipment aging management program is an existing preventive program that implements the Environmental Qualification (EQ) requirements in 10 CFR Part 50, Appendix A, Criterion 4, and 10 CFR 50.49. The BFN Environmental Qualification of Electric Equipment program demonstrates that electrical equipment in the EQ program located in harsh plant environments will perform their safety function 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 EQ. To meet this requirement, the program performs TLAAs that establish the equipment service condition tolerance and aging limits (e.g., qualified life or condition limit). These analyses provide justification for life extension of the BFN EQ equipment from 60 years to 80 years. The program

manages thermal, radiation, and cyclical aging for components subject to 10 CFR 50.49 requirements through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. Components subject to 10 CFR 50.49 requirements not qualified for the license term are to be refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation.

The program is implemented in accordance 10 CFR 50.49 and 10 CFR 54.21(c)(1)(iii). The program demonstrates the acceptability of the EQ TLAAs under 10 CFR 54.21(c)(1).

The Environmental Qualification of Electric Equipment aging management program will be enhanced to:

1. Revise implementing procedures to add activities to visually inspect accessible, passive EQ equipment located in adverse localized environments at least once every 10 years. The first periodic visual inspection will be performed prior to the subsequent period of extended operation.
2. Revise implementing procedures to establish acceptance criteria for the visual inspections of accessible, passive EQ equipment located in adverse localized environments.

These program enhancements will be implemented no later than six months prior to the subsequent period of extended operation. Inspections and tests that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.

A.4.0 Time-Limited Aging Analyses

A.4.1 Identification and Evaluation 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 period of extended operation be provided. The TLAAs identified and evaluated to meet these requirements are described below.

10 CFR 54.21(c)(2) also 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 period of extended operation. No plant-specific exemptions granted pursuant to 10 CFR 50.12 were identified for BFN that are based upon a TLAA. Therefore, no further evaluation is required for plant-specific exemptions granted pursuant to 10 CFR 50.12.

A.4.2 Reactor Vessel and Internals Neutron Embrittlement Analyses

10 CFR 50.60 requires that all light-water reactors meet the fracture toughness, P-T limits, and material surveillance program requirements for the reactor coolant pressure boundary as set forth in 10 CFR 50, Appendices G and H. The current reactor vessel embrittlement calculations for BFN that evaluate reduction of fracture toughness of the Units 1, 2, and 3 reactor vessel beltline materials for 60 years are based upon a predicted end-of-license fluence applicable for 38 Effective Full Power Years (EFPY) for Unit 1, and 48 EFPY for Unit 2, and 54 EPFY for Unit 3. These analyses have been identified as TLAAs as defined in 10 CFR 54.21(c) and have been reevaluated for the increased neutron fluence associated with 80 years of operation as described

in the subsections below. These subsections also include evaluations of the increased neutron fluence on reactor internal components, including potential loss of preload for the core plate rim hold-down bolts, jet pump slip joint clamps, jet pump auxiliary spring wedge assemblies, jet pump riser clamps, jet pump sensing line clamps, core spray replacement piping and clamps, and access hole cover repairs; as well as irradiation-enhanced stress relaxation of the replacement core plate extended life plugs.

A.4.2.1 Reactor Vessel and Internals Neutron Fluence Analyses

High energy (E > 1.0 MeV) neutron fluence has been projected for 80 years, and each unit was projected to a different amount of Effective Full Power Years (EFPY). Unit 1 is projected to reach 50 EFPY in 80 years, Unit 2 is projected to reach 64 EFPY in 80 years, and Unit 3 is projected to reach 62 EFPY in 80 years. The fluence projections have been used in the evaluation of the neutron embrittlement TLAAs. A singular fluence methodology was utilized to develop the 80-year projections and is described below.

- TransWare Radiation Analysis Modeling Application (RAMA) methodology has been used to develop 80-year fluence projections for the reactor vessel and vessel internal components that are used in evaluating TLAAs in Sections A.4.2.1.1, A.4.2.1.2, and A.4.2.2 through A.4.2.16.

Below is a summary BFN historical operating power levels which have been considered in developing the 80-year fluence projections:

- The Original Licensed Thermal Power (OLTP) level for BFN Units 1, 2 and 3 was 3293 megawatts thermal (MWt).
- By Amendment Nos. 254 and 214 (Units 2 and 3 respectively) dated September 8, 1998, the NRC approved an approximate 5 percent stretch power uprate to 3458 MWt for BFN Units 2 and 3. By Amendment No. 269 (Unit 1) dated March 6, 2007, the NRC approved an approximate 5 percent stretch power uprate to 3458 MWt for BFN Unit 1.
- By Amendment Nos. 299, 323 and 283 (Units 1, 2 and 3, respectively) dated August 14, 2017, the NRC approved an approximate 15 percent EPU (Extended Power Uprate) that authorized an increase in the maximum thermal power level from 3458 MWt to the current licensed thermal power (CLTP) level of 3952 MWt for BFN Units 1, 2, and 3. The EPU power level of 3952 MWt represents an increase of approximately 20 percent above the OLTP level of 3293 MWt.
- By Amendment Nos. 310, 333 and 293 (Units 1, 2 and 3, respectively), dated December 26, 2019, the NRC approved a Maximum Extended Load Line Limit Analysis Plus (MELLLA+) operating strategy for BFN Units 1, 2, and 3.

The current uprated power level of 3952 MWt is the maximum power level evaluated for the subsequent period of extended operation.

A.4.2.1.1 Reactor Vessel Neutron Fluence Analyses

Reactor vessel fluence projections for 80 years have been developed using the NRC approved Transware Radiation Analysis Modeling Application (RAMA) Fluence Methodology. The RAMA methodology adheres to the guidance in NRC Regulatory Guide 1.190 for neutron flux evaluations. The fluence projection values have been used in the evaluation of the neutron embrittlement TLAAs for reactor vessel beltline materials, which include the reactor vessel plate materials, welds, and nozzle forgings. Fluence projections have been developed to evaluate fluence-based reactor vessel TLAAs and to determine when specified fluence threshold values may be exceeded that are used to invoke specific aging management requirements, such as inspections, for these components.

The BFN Unit 1, 2, and 3 reactor vessel beltline component fluence analyses have been projected through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.1.2 Reactor Vessel Internals Neutron Fluence Analyses

Fluence projections have been developed for 80 years for reactor vessel internal components using the Transware Radiation Analysis Modeling Application (RAMA) Fluence Methodology. Use of this model was performed in accordance with NRC Regulatory Guide 1.190. The fluence projections have been developed for specific reactor vessel internal components to evaluate fluence-based TLAAs and to determine when specified fluence threshold values may be exceeded that are used to invoke specific aging management requirements, such as inspections, for these components.

The Units 1, 2, and Unit 3 reactor vessel internal component fluence analyses have been projected through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.2 Reactor Vessel Upper-Shelf Energy (USE) Analyses

The Appendix G of 10 CFR 50, Paragraph IV.A.1.a, states that reactor vessel beltline materials must have Charpy upper-shelf energy (USE) throughout the life of the vessel of no less than 50 ft-lb, unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy upper-shelf energy will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code.

The BFN Unit 1, 2, and 3 reactor vessels were designed and fabricated prior to the current requirements, and as a result, there is insufficient data available to establish the initial unirradiated USE value for all beltline materials for the reactor vessels. Therefore, the current licensing basis Charpy USE evaluations are based upon Equivalent Margin Analysis (EMA) as specified in BWRVIP-74-A, which meets the alternative requirements specified above. The BFN Units 1, 2, and 3, 2017 EPU amendment submittal re-evaluated EMA for 60 years. Therefore, these analyses have been identified as TLAAs requiring evaluation for the subsequent period of extended operation.

An EMA has been performed for the limiting beltline plate and weld materials for 80 years of operation at 50 EFPY for Unit 1, 64 EFPY for Unit 2, and 62 EFPY for Unit 3, and then compared against the 54 EFPY limits defined in Appendix B of BWRVIP-74-A. The comparison concluded that the Unit 1, 2, and 3 vessel materials meet the 54 EFPY limits defined in Appendix B of BWRVIP-74-A, and the USE values for Unit 1, 2 and Unit 3 reactor vessel beltline materials have been satisfactorily evaluated for the subsequent period of extended operation based upon the updated EMA values determined using 80-year fluence projections. Therefore, the Equivalent Margins Analyses have been projected through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.3 Reactor Vessel Adjusted Reference Temperature (ART) Analyses

The adjusted reference temperature (ART) of the limiting beltline material is used to adjust the P-T limit curves to account for irradiation effects. The initial nil-ductility reference temperature (RT_{NDT}) is the temperature at which an unirradiated ferritic steel material changes in fracture characteristics from ductile to brittle behavior. RT_{NDT} is evaluated according to the procedures in the ASME Code. Neutron embrittlement increases the RT_{NDT} beyond its initial value.

10 CFR 50, Appendix G, defines the fracture toughness requirements for the life of the vessel. The shift in the initial RT_{NDT} (ΔRT_{NDT}) is evaluated as the difference in the 30 ft lb index temperatures from the average Charpy curves measured before and after irradiation. This increase (ΔRT_{NDT}) determines how much higher the vessel temperature must be raised for the material to continue to act in a ductile manner. The ART is defined as: Initial RT_{NDT} + ΔRT_{NDT} + Margin. The ΔRT_{NDT} and ART calculations meet the criteria of 10 CFR 54.3(a). Therefore, these analyses have been identified as TLAAs requiring evaluation for the subsequent period of extended operation.

The 80-year ART values have been determined for BFN Units 1 (50 EFPY), 2 (64 EFPY), and 3 (62 EFPY) beltline materials using the methodology specified in NRC Regulatory Guide 1.99, Revision 2. The 80-year ART values of the limiting beltline materials for each unit remain below 200 degrees F, which is the RT_{NDT} limit.

The 80-year ART analyses have been projected through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(ii).

A.4.2.4 Reactor Vessel Pressure-Temperature (P-T) Limits

10 CFR 50 Appendix G requires that the reactor vessel be maintained within established pressure-temperature (P-T) limits, including heatup and cooldown operations. These limits specify the minimum acceptable reactor coolant temperature as a function of reactor pressure. As the reactor vessel is exposed to increased neutron irradiation over time, its fracture toughness is reduced. The P-T limits must account for the change in material properties due to anticipated reactor vessel fluence.

The currently licensed Pressure-Temperature (P-T) limit curves are located in the BFN Units 1, 2, and 3, Technical Specification 3.4.9, Reactor Coolant System Pressure and Temperature Limits. The currently licensed BFN P-T limit curves were developed for up to 38 EFPY for Unit 1, 48 EFPY for Unit 2, and 54 EFPY for Unit 3. Since the P-T limit curves are based on EFPY projections for the currently approved 60-year operating term, the P-T limit curves have been identified as TLAAs requiring evaluation for the subsequent period of extended operation.

In accordance with NUREG-2192, Section 4.2.2.1.4, the P-T limits for the subsequent period of extended operation will be updated at the appropriate time through the plant's applicable Technical Specification change processes for updating the P-T limit curves prior to the plant's entry into the subsequent period of extended operation. The 10 CFR 50.90 process, which constitutes the CLB, will ensure that the P-T limits for the subsequent period of extended operation will be updated prior to expiration of the P-T limits for the current period of operation.

Therefore, the effects of aging on the intended function(s) of the reactor vessels will be adequately managed through the subsequent period of extended operation using the

10 CFR 50.90 process for P-T limits located in the limiting conditions of operations of the Technical Specifications, in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.2.5 Reactor Vessel Circumferential Weld Failure Probability Analyses

BFN has previously applied for and been granted relief from reactor vessel circumferential weld inspection for the Units 1, 2 and 3 vessels. The relief from inspection is based on assessment of the probability of failure of the limiting circumferential weld. This assessment is based on fluence values associated with 60 years of operation and has therefore been identified as a TLAA requiring evaluation for the subsequent period of extended operation.

The 80-year unit-specific fluence values have been projected for each circumferential weld and end of interval (EOI) RT_{MAX} values have been then determined to evaluate the BFN Units 1, 2, and 3 circumferential weld failure probabilities. The BFN EOI RT_{MAX} values based on the unit-specific 80-year fluence values are less than the Limiting RT_{MAX} values present in BWRVIP-329-A. Therefore, the conditional probability of failure is bounding for BFN Units 1, 2, and 3 and meet the applicability criteria of BWRVIP-329-A.

Reapplication for relief from circumferential weld examination will be made in accordance with 10 CFR 50.55a(a)(3) in time for NRC review and approval prior to the subsequent period of extended operation. The plant-specific information described above demonstrates that at the end of the subsequent period of extended operation, the circumferential beltline weld materials meet the safety goals described in BWRVIP-329-A. These analyses will be managed in accordance with 10 CFR 54.21(c)(1)(iii) by requesting relief from circumferential weld inspection using the 10 CFR 50.55a process.

A.4.2.6 Reactor Vessel Axial Weld Failure Probability Analyses

The BWRVIP recommendations for inspection of reactor vessel shell welds in BWRVIP-05 include examination of 100 percent of the axial welds and inspection of the circumferential welds only at the intersections of these welds with the axial welds. The scope and evaluation for BWRVIP-05 was limited to 40 years of plant operation.

Subsequently, BWRVIP-329-A and the associated NRC safety evaluation report (SER) provide additional technical basis for an assessment of axial weld integrity for extended operations of up to 80 years. Since these failure probability assessments are applicable to BFN Units 1, 2, and 3, they are identified as TLAAs requiring evaluation through the subsequent period of extended operation.

The 80-year unit-specific fluence values have been projected for each axial weld and end of interval (EOI) RT_{MAX} values have been then determined to evaluate the BFN Units 1, 2, and 3 axial weld failure probabilities. The BFN EOI RT_{MAX} values based on the unit-specific 80-year fluence values are less than the Limiting RT_{MAX} values present in BWRVIP-329-A.

The conditional probability of failure for the axial welds is bounding for BFN Units 1, 2, and 3 and meet the applicability criteria of BWRVIP-329-A. This analysis has been projected through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.7 Reactor Vessel Reflood Thermal Shock Analysis

10 CFR 50 Appendix A, General Design Criterion 31 requires that the reactor coolant pressure boundary of a light water reactor be designed such that it possesses adequate margin against non-ductile failure for all postulated conditions. For boiling water reactors, this requirement is demonstrated both by development of Pressure-Temperature Limit Curves, which are addressed in Section A.4.2.4, and by reference to a generic fracture mechanics analysis that evaluates the effects of the limiting Loss of Coolant Accident (LOCA) event.

The generic fracture mechanics analysis evaluates the effects of a postulated LOCA on the structural integrity of a reactor vessel. The rupture of a main steam line was determined to bound all other LOCA events with respect to this evaluation. After the rupture, several emergency core cooling systems are activated at different times and the vessel is flooded with cooling water. The vessel depressurization and the subsequent injection of cold water to reflood the reactor vessel produce a rapid reduction in temperature and high thermal stresses in the vessel. The analysis concludes that the reactor vessel has a considerable margin to failure by brittle fracture even in the presence of postulated pre-existing flaws. This generic analysis envelopes BFN and is based on BWR vessel material properties and cumulative fluence assumed for 40 years of operation. The generic failure analysis was reevaluated for 60 years of operation as part of the original license renewal applications. Therefore, this analysis has been identified as a TLAA requiring evaluation for the subsequent period of extended operation.

An updated 80-year fracture mechanics evaluation was performed for the reflood thermal shock event to evaluate components with the limiting material properties from the BFN Units 1, 2, and 3 reactor vessel beltline plates, axial welds, and circumferential welds, which bounds the remainder. The analysis used the projected 80-year fluence values and determined that during the subsequent period of extended operation, each reactor vessel has sufficient toughness margin to prevent unacceptable flaw propagation due to thermal shock during reflooding after LOCA events.

The reactor vessel reflood thermal shock analysis has been projected through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.8 Core Shroud Reflood Thermal Shock Analysis

Neutron irradiation embrittlement may affect the ability of reactor vessel core shroud to withstand a low-pressure coolant injection thermal shock transient. The BFN reactor vessel core shrouds, which were fabricated from Type 304 stainless steel, have been analyzed for a low-pressure coolant injection reflood thermal shock transient considering the embrittlement effects of neutron irradiation exposure for the initial license renewal project and validated for a 60-year extended operating term. The core shrouds receive the maximum irradiation on the inside surface approximately opposite the midpoint of the fuel centerline. The maximum thermal shock stress in this region was determined to be 155,700 psi at the midpoint of the shroud, which is equivalent to 0.57% strain during the reflood thermal shock transient. This analysis has been identified as a TLAA requiring evaluation for the subsequent of extended operation.

In Request for Additional Information responses for the 60-year initial License Renewal Application, BFN provided material destructive testing results of highly irradiated Type 304 stainless steel to demonstrate that the core shrouds would withstand a low-pressure coolant injection event. These conclusions were accepted by the NRC. For this TLAA, BFN evaluated two material properties: % area reduction (%RA) and % elongation.

For the %RA analysis, BFN concluded that a fluence value of 5.34E+21 n/cm^2 over the life of the core shroud results in sufficient ductility during the reflood thermal shock transient to resist the 155,700 psi stress. For the % elongation analysis, BFN concluded that a fluence value of 8.0E+21 n/cm^2 over the life of the core shroud results in strain values, during the reflood thermal shock transient, which bound the 0.57% strain.

The projected 80-year shroud fluence values for BFN Units 1, 2, and 3 are less than the calculated 60-year fluence values established for the BFN initial License Renewal Application. Because the measured value of elongation bounds the calculated thermal shock strain amplitude, the calculated thermal shock strain at the most irradiated location is acceptable considering the loss of ductility effects for an 80-year operating period. Therefore, the analysis has been projected through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.9 Core Plate Hold-Down Bolt Loss of Preload Analysis

The reactor vessel core plate is attached to the core support structure by 34 stainless steel hold-down bolts arranged along the rim of the plate. The bolts were preloaded during initial installation but are subject to stress relaxation (loss of preload) because of irradiation effects. The stress state of these bolts was evaluated as part of the analysis performed by General Electric Hitachi (GEH) to prepare BWRVIP-25 Revision 0, “BWR Vessel and Internals Project BWR Core Plate Inspection and Flaw Evaluations Guidelines.”

As described in the Safety Evaluation to BWRVIP-25-A, “BWR Core Plate Inspection and Flaw Evaluation Guidelines,” plants must consider relaxation of the rim hold down bolts as a TLAA issue. Since BFN has not installed core plate wedges, the loss of preload must be considered in the TLAA evaluation.

The 80-year RAMA fluence projections were prepared for the BFN Units 1, 2, and 3 core plate hold-down bolts. An analysis of the core plate rim hold-down bolts was assessed per the BWRVIP 25 Revision 1-A guidance in Appendix I. The evaluation has been projected to the end of the subsequent period of extended operation (from bounding fluence of 5E+19 n/cm^2 for extended operation to 1.41E+20 n/cm^2 for subsequent period of extended operation).

The analysis concluded that the criteria of BWRVIP-25 Revision 1-A were satisfied and justifies the elimination of the core plate bolt inspections at BFN during the subsequent period of extended operation. This TLAA is dispositioned per 10 CFR 54.21(c)(1)(ii), as the evaluation has been projected to the end of the subsequent period of extended operation.

A.4.2.10 Jet Pump Slip Joint Repair Clamp Loss of Preload Analysis

Jet pump slip joint repair clamps have been designed and installed on jet pumps in BFN Units 1 and 2 to minimize slip joint vibration and wear of the jet pump assemblies. Three slip joint repair clamps remain on Unit 1, and eight remain on Unit 2. None have been installed in Unit 3. The clamps apply a lateral preload to the slip joint, between the exit end of the inlet-mixer and the entrance end of the diffuser, to dampen jet pump vibration. The design analysis for the clamps evaluated a neutron fluence value of 3.02E+18 n/cm^2 for a 40-year design life of the clamp and demonstrated that loss of preload resulting from neutron fluence during the design life of the clamps was acceptable. The structural evaluation states that the “cold” bolt preload is

550 pounds at 100ºF, the initial “hot” preload at 550ºF is 500 pounds, and the minimum, end-of-life preload is 350 pounds at 550ºF. This analysis was identified as a TLAA.

Fluence at clamp locations inside the reactor vessel were determined from initial clamp installation (Unit 1 at the start of cycle 13, Unit 2 at the start of cycle 14) through the end of the subsequent period of extended operation. The peak fluence value is projected to reach 4.98E+18 n/cm^2 (Unit 1) and 6.83E+18 n/cm^2 (Unit 2) at the end of the subsequent period of extended operation. These values are more than the design value of 3.02E+18 n/cm^2, so further evaluation was required to determine the acceptability from the loss of preload.

An evaluation was performed to determine the preload loss in the jet pump slip joint repair clamps. The maximum calculated relaxation (in % loss compared to original specification) is 12 for Unit 1 and 16 for Unit 2. This does not diminish the preload past the end-of-life requirement of 350 lbs. Therefore, the design analysis has been projected to the end of the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.11 Jet Pump Auxiliary Spring Wedge Assembly Loss of Preload Analysis

The BFN jet pump (JP) assemblies have had auxiliary spring wedge assemblies installed to maintain lateral support for the jet pump inlet mixer. The design stress analysis considered potential aging effects, including loss of preload due to radiation effects based upon a design life of 40 years.

The auxiliary spring wedge assemblies were installed in Units 1, 2, and 3 on varying jet pumps. The oldest auxiliary spring wedge assemblies were installed during refuel outage 6 for Unit 1, refuel outage 13 for Unit 2, and refuel outage 12 for Unit 3.

The auxiliary spring wedge assembly design analysis determined that the fluence levels in the regions where the auxiliary wedges are installed on the jet pumps are less than 1.81E+20 n/cm^2 for a 40-year design life. This analysis was identified as a TLAA.

To evaluate this TLAA, fluence projections were calculated for the limiting auxiliary spring wedge assembly for each unit. For Unit 1, the maximum fluence at the limiting auxiliary spring wedge assembly was determined to be 1.52E+20 n/cm^2, and for Units 2 and 3, the maximum fluence at the limiting auxiliary spring wedge assembly was determined to be 1.55E+20 n/cm^2. Each of these fluence values are less than the 1.81E+20 n/cm^2 fluence value assumed in the design structural analysis. Therefore, the design analysis remains valid through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.2.12 Jet Pump Riser Repair Clamp Loss of Preload Analysis

During November 1991, crack indications were identified at the two attachment welds of the riser brace to the riser pipe adjacent to JP 5 at reactor vessel 90° azimuth on BFN Unit 3.
A mechanical clamping system designed to structurally replace these welds was installed on both jet pump risers in 1995 prior the restart of Unit 3. Since these clamps use bolts to maintain the proper clamping force, loss of preload due to neutron irradiation stress relaxation was a design consideration. The stress analysis of the clamp analyzed preload losses based on neutron fluence of 1.89E+20 n/cm^2 for the clamp bolt and 3.15E+20 n/cm^2 for the support bolt. Since the neutron fluence values were assumed through the end of the initial 40 years of

operation, the design analysis has been identified as a TLAA that requires evaluation for the subsequent period of extended operation./

To determine if this fluence assumption will remain valid through 80 years of operation, neutron fluence was projected through the subsequent period of extended operation. The 62 EFPY fluence value at the limiting Unit 3 jet pump riser clamp location was determined to be 1.38E+20 n/cm^2, which is less than the 1.89E+20 n/cm^2 fluence value assumed in the design specification for the clamp. Therefore, the design analysis remains valid through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.2.13 Replacement Core Support Plate Plug Extended Life Irradiation - Enhanced Stress Relaxation Analysis

The original design of the BFN Units 1, 2, and 3 core support plates included holes for bypass flow. It was discovered that the flow through the holes produced high velocity jets that impinged on the in-core instrument tubes, subjecting them to high levels of flow induced vibration, and leading to wear on the adjacent fuel channels. The core support plate holes were plugged to prevent the unwanted flow induced vibration.

BFN Units 2, and 3 have had all the original core support plate plugs replaced. BFN Unit 1 has had only a small population of core support plate plugs replaced. The original core support plate plugs had a service life of approximately 14 years. The extended life core support plate plugs have a service life of 35 EFPY corresponding to a fluence of 5.25E+20 n/cm^2.

Due to the effects of irradiation-enhanced stress relaxation, the amount of force applied by the plug mandrel spring is dependent on the accumulated neutron fluence. Irradiation-enhanced stress relaxation of the mandrel spring due to neutron irradiation has been identified as a TLAA and must be evaluated for the subsequent period of extended operation.

An analysis was prepared to evaluate the acceptability of the core support plate plug preload loss during the subsequent period of extended operation. The analysis concluded an acceptable fluence value for the replacement core support plate plugs. Since the calculated fluence values are less than the design fluence value, the extended life of the core support plate plugs has no adverse impact on the acceptability of the component's operation during the subsequent period of extended operation.

The analysis has been projected through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.14 Irradiation Assisted Stress Corrosion Cracking (IASCC) of Reactor Vessel Internals

Section 4.7.6 of the BFN initial License Renewal Application concludes that the expected fluence on the core shroud, top guide, core plate, and in-core instrumentation dry tubes and guide tubes exceed the threshold of 5.0E+20 n/cm^2 at the end of the 60-year initial period of extended operation. These analyses have been identified as a TLAA that requires evaluation for the subsequent period of extended operation.

Fluence projections for BFN Units 1, 2, and 3 core shroud, top guide, core plate, and in-core instrumentation dry tubes exceed the screening criteria of 5.0E+20 n/cm^2 at the end of the subsequent period of extended operation. Therefore, these components will be inspected periodically for cracking and loss of fracture toughness (embrittlement) during the subsequent period of extended operation in accordance with the BWR Vessel Internals aging management program (A.2.1.7).

The effects of aging on the intended function(s) of the reactor vessel core shroud, top guide, core plate, and in-core instrumentation dry tubes will be adequately managed through the subsequent period of extended operation by the BWR Vessel Internals program, in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.2.15 Core Spray Replacement Piping Bolting Loss of Preload Evaluation

A sectional replacement of the lower core spray sparger line was installed on BFN Unit 3. The repair is a bolted replacement of the lower section of the core spray piping in the downcomer region.

The design specification for this repair component states that the fast neutron flux (E > 1.0 MeV) at the repair locations is less than 4.8E+10 n/cm^{2}s, and that it will not affect the properties of the lower sectional replacement materials for the design life of 40 years. Calculating a conservative fluence value (assume 100% capacity factor) from this flux using a 40-year design life equates to 6.05E+19 n/cm^2.

Since the design report evaluated the effects of fluence on loss of preload over a 40-year service life, the evaluation has been identified as a TLAA that requires evaluation for the subsequent period of extended operation.

The 62 EFPY fluence value for the Unit 3 core spray replacement piping location was determined to be 4.82E+17 n/cm^2. This is less the originally analyzed value of 6.05E+19 n/cm^2, and the Unit 3 replacement core spray piping bolting loss of preload evaluation remains valid through the subsequent period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

A.4.2.16 Core Spray Sparger Repair Clamp Loss of Preload Evaluation

A repair clamp device was installed during the Unit 1 restart effort due to cracking found in the heat affected zone of the core spray sparger T-box. The clamp assembly will be subject to high neutron irradiation and the fasteners which were preloaded during installation will be relaxed.

Per review of the design analysis, it is specified that the relaxation of the bolt preload due to fast neutron fluence of 1.4E+19 n/cm^2 for a 40-year design life is considered in the evaluation.

An evaluation was prepared to determine the irradiation induced loss of preload in the core spray sparger repair clamp. Although the projected fluence for 80-years of operation exceeded the original design fluence threshold, the evaluation showed that it was appropriate to compare the fluence to the screening criteria from BWRVIP-315. The calculated fluence was less than the screening criteria in BWRVIP-315. Therefore, the core spray sparger repair clamp loss of preload evaluation has been projected through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.17 Access Hole Cover Repair Loss of Preload Evaluation

The Unit 1 welded access hole covers were replaced with a bolted design, due to cracking at the original welded connection between the shroud baffle plate and access hole cover. This repair was also installed in 2023 for Unit 2. The same repair is scheduled to be installed in Unit 3 in 2024.

The replacement access hole cover fasteners are preloaded when installed and have been evaluated considering a 20% preload relaxation over a 40-year design life. Since the design report evaluated the effects of fluence on loss of preload over the design life, the evaluation has been identified as a TLAA that requires evaluation for the subsequent period of extended operation.

An evaluation was prepared to determine the irradiation induced preload loss in the access hole cover repair bolts. The analysis found that due to the low accumulated fluence in the access hole area, the expected preload loss was less than 1%. Therefore, the analysis remains valid for the subsequent period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

A.4.2.18 Jet Pump Hold-Down Beam Assembly Loss of Preload Analysis

All BFN jet pump assemblies have had jet pump hold-down beam assemblies installed. The original hold down beam assemblies have been replaced with Group 2 beam bolt assemblies. On Unit 3, the Jet Pump (JP) 19 and JP 20 beam bolt assemblies were replaced with Group 3 beam bolt assemblies. The Group 2 and Group 3 beam bolt assemblies are constructed of X-750 alloy. The axial compressive bolt is preloaded, and over time this preload is relaxed due to the thermal environment and neutron irradiation of the component.

An evaluation was prepared to determine if the calculated preload loss in the JP beam bolts was acceptable for the subsequent period of extended operation. The analysis showed that compared to the acceptable fluence levels for both Group 2 and Group 3 beam bolt assemblies, the calculated fluence values were bounded by the thresholds. Therefore, Therefore, the BFN jet pump hold-down beam assembly loss of preload analysis has been projected to the end of the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.2.19 Jet Pump Sensing Line Clamps Loss of Preload Analysis

Jet pump sensing line clamps were installed on BFN Units 1, 2, and 3 to mitigate increased vibration excitation associated with uprated power conditions. The modification consists of a C-clamp assembly which clamps tightly to both the diffuser and the sensing line. Over the design life of the clamp, the bolt preload will be reduced due to thermal and irradiation induced relaxation.

An evaluation was prepared to determine if the calculated preload loss in the sensing line clamp was acceptable for the subsequent period of extended operation. The evaluation found that the calculated fluence values which correspond to the end of the subsequent period of extended operation are bounded by the original design threshold values. Therefore, the loss of preload analysis for the jet pump sensing line clamps remains valid for the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.3 Metal Fatigue Analyses

Metal fatigue was considered explicitly in the design process for pressure boundary components designed in accordance with ASME Section III, Class 1 requirements. Metal fatigue was evaluated implicitly for components designed in accordance with ASME Section III, Class 2 or 3 requirements, or ANSI B31.1 requirements. Each of these fatigue analyses and evaluations are considered to be Time-Limited Aging Analyses (TLAAs) requiring evaluation for the subsequent period of extended operation in accordance with 10 CFR 54.21(c) as described below.

A.4.3.1 Transient Cycle and Cumulative Usage Projections For 80 Years

Fatigue analyses are based upon explicit numbers and amplitudes of thermal and pressure transients usually described in design specifications. The intent of the design basis transient definitions is to bound a wide range of possible events with varying ranges of severity in temperature and pressure. Since the existing fatigue analyses are based upon a number of transient cycles postulated to bound 60 years of service, projection of the transient cycles through the subsequent period of extended operation is required to demonstrate that the analyses and waivers remain valid.

Projections of the transient cycles through the subsequent period of extended operations were developed for 80 years and used as input to calculate projected 80-year Cumulative Usage Factor (CUF) and Environmentally-Assisted Cumulative Usage Factor (CUF_{en}) values to determine whether the existing analyses remain valid for 80 years. The number of transient cycles, CUF values, and CUF_{en} values have been projected through the subsequent period of extended operation. The following fatigue TLAAs have been dispositioned using the projected number of transient cycles, CUF values, and CUF_{en} values through the subsequent period of extended operation.

A.4.3.2 Metal Fatigue of Class 1 Components

The BFN reactor vessels were originally designed for 40 years of service in accordance with the ASME Code Section III, its interpretations, and applicable requirements, (including Summer 1965 Addenda for Units 1 and 2, and Summer 1966 Addenda for Unit 3) for Class 1 design requirements. The reactor vessel Class 1 fatigue analyses determined the effects of transient cyclic loadings resulting from changes in system temperature and pressure and for seismic loading cycles. The fatigue analyses evaluated explicit numbers and types of transients that were postulated for the 40-year design life of the plant in the design specifications. These Class 1 explicit fatigue analyses were required to demonstrate that the CUF for each component will not exceed the design limit of 1.0 for all the postulated transients. As stipulated in the BFN initial License Renewal Application the original 40-year reactor vessel explicit fatigue analyses were updated with 60-year projected transient cycle numbers. The 60-year evaluations now serve as the current licensing basis (CLB) and have been identified as TLAAs for the subsequent period of extended operation.

The 80-year CUF and CUF_{en} projections show that all ASME Section III, Class 1 fatigue analysis will continue to meet the ASME Section III design limit of 1.0 through the subsequent period of extended operation. To ensure the projected CUF and CUF_{en} values remain acceptable for the 80-year period of operation, the Fatigue Monitoring program (A.3.1.1) will monitor cumulative CUF and CUF_{en} for limiting locations though the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.3.3 Class 1 Fatigue Waivers

The BFN reactor vessels were originally designed for 40 years of service in accordance with the ASME Code Section III 1965 Edition, its interpretations, and applicable requirements, (including Summer 1965 Addendum for the Units 1 and 2 reactor vessels and Summer 1966 Addendum for the Unit 3 reactor vessel) for Class 1 design requirements. The design stress reports for the Unit 1, 2, and Unit 3 reactor vessels include fatigue waivers that determined that some reactor vessel nozzles did not require explicit fatigue analyses because the criteria from ASME Section III, Paragraph N-415.1 were satisfied.

Since the ASME Section III, Paragraph N-415.1 fatigue waiver criteria require postulated cycle input for the intended operating life of the plant, the fatigue waivers for the applicable BFN reactor vessel nozzles are TLAAs. Therefore, these fatigue waiver evaluations were re-evaluated for the subsequent period of extended operation using the 80-year projected number of transients. The results of the reevaluation show that the criteria in ASME Section III, Paragraph N-415-1 remain satisfied through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.3.4 Metal Fatigue of Non-Class 1 Components

Piping designed in accordance with ASME Section III, Class 2 or 3, or ANSI B31.1 Piping Code design rules is not required to have an explicit analysis of cumulative fatigue usage, but cyclic loading is considered in the design process. If the numbers of anticipated thermal cycles exceed specified limits, these codes require the application of a stress range reduction factor to the allowable stress to prevent damage from cyclic loading. This is an implicit fatigue analysis since it is based upon the anticipated number of cycles for the life of the piping system.

These codes first require the overall number of thermal and pressure cycles expected during the plant lifetime of these components to be determined. A stress range reduction factor is then determined for that number of cycles using the applicable design code. If the total number of cycles is 7,000 or less, the stress range reduction factor of 1.0 is applied, which would not reduce the allowable stress values. For higher numbers of cycles, the stress range reduction factors limit the allowable stresses that can be applied to the piping.

Portions of the following Class 2 and 3 and ANSI B31.1 piping systems within the scope of license renewal are directly connected to Reactor Coolant System (RCS) and are affected by the same operational transients that result in thermal cycles for the attached Class 1 RCS piping: Control Rod Drive, Core Spray, Feedwater, Main Steam, Containment Atmosphere Dilution, Residual Heat Removal (including Residual Heat Removal Service Water since transients are bounded the Residual Heart Removal transients), and Standby Liquid Control Systems. These transient cycles have been projected for 80 years. The projections demonstrate that the stress range reduction factors originally applied for the components within these piping systems remain applicable. Therefore, these TLAAs have been demonstrated to remain valid through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

For the remaining Class 2 and 3 and ANSI B31.1 piping systems within the scope of subsequent license renewal that are affected by thermal and pressure transients that are different than the RCS transients, an operational review was performed. These piping systems include portions of the Condensate and Demineralized Water, Emergency High Pressure Makeup, Auxiliary Boiler, High Pressure Fire Protection (Diesel Driven Pump), Carbon Dioxide, Off-Gas, Reactor Water Cleanup, Reactor Core Isolation Cooling (steam supply and turbine exhaust piping), High

Pressure Coolant Injection (steam supply and turbine exhaust piping), Standby Diesel Generator, and Radiation Monitoring Systems.

The review concluded that the total number of thermal cycles for these systems, projected through the period of extended operation, will not exceed 68 percent of the 7,000-cycle threshold. Therefore, the stress range reduction factors originally selected for the Class 2 and 3 and ANSI B31.1 piping systems remain applicable and these TLAAs have been demonstrated to remain valid through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.3.5 Environmental Fatigue Analyses for Reactor Vessel and Class 1 Piping

NUREG-2191 Section X.M1, Fatigue Monitoring, provides guidance for evaluating the effects of the reactor water environment on the fatigue life of ASME Section III Class 1 components that contact the reactor coolant. One acceptable method for satisfying this guidance is to assess the impact of the reactor coolant environment on a sample set of critical components. Plant-specific evaluations were performed for the locations identified in NUREG/CR-6260. For these locations, the CUF_{en} values are calculated in accordance with NUREG/CR-6909, Revision 0 (Reference 4.8.48), NUREG/CR-6583 (Reference 4.8.50), and NUREG/CR-5704 (Reference 4.8.51) and are tracked by the Fatigue Monitoring program (A.3.1.1).

The Fatigue Monitoring program ensures that the Environmental-Assisted Cumulative Usage Factors (CUF_{en}) are maintained below the design limit of 1.0. Per 10 CFR.54.21(c)(iii), the Fatigue Monitoring program is credited with managing the effects of environmental fatigue on the intended functions of all reactor vessel and Class 1 piping components through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.3.6 Replacement Steam Dryer Stress Report and Fatigue Evaluation

To support the Extended Power Uprate (EPU) project, BFN Units 1, 2, and 3 replaced the reactor vessel steam dryers. The new replacement steam dryers are nonsafety-related items and are classified as Internal Structures as defined in the ASME Boiler and Pressure Vessel Code, Section III (1989 Edition no Addenda), Subsection NG Paragraph NG-1122. The replacement steam dryers are not components governed by ASME Code, Section III, however the design was evaluated in 2015 and does comply with stress and fatigue criteria for core support structures defined in ASME Code Subsection NG-3000, with exceptions as described in NEDC-33824P, “Browns Ferry Replacement Steam Dryer Stress Analysis,” dated August 2015. This evaluation has been identified as a TLAA that requires evaluation for the subsequent period of extended operation.

The steam dryer structural analyses were performed assuming that the new replacement steam dryers would be operated for 40 to 60 years. The BFN Units 1, 2, and 3 new replacement steam dryers were put in service in 2018 (for Unit 1 and Unit 3) and 2019 (for Unit 2). The period of subsequent extended operation would expire in 2053 for Unit 1, 2054 for Unit 2, and 2056 Unit 3. Given the 40 to 60 year period assumed in the structural analyses for the new replacement steam dryers, the current structural analysis would remain valid for each of the BFN units.

Therefore, the replacement steam dryer fatigue evaluation remains valid through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.3.7 Emergency Equipment Cooling Water System Weld Flaws Evaluation

Analysis was performed on 27 EECW system piping welds which have flaws that are larger than normally considered acceptable. The analysis included a stress evaluation of the flawed welds and fatigue crack growth calculations. The fatigue crack growth calculations were based on a conservative projection of 125 cycles.

Seventeen of the 27 weld flaws were reevaluated, and the number of cycles to exceed the allowable crack depth increased from 125 to 2,600 cycles. This cycle limit is bounding for all 27 weld flaws, as it was calculated from the weld with the smallest number of allowable cycles (Weld 2-AC-09B, which corresponds to Residual Heat Removal Pump Room Coolers 2A and 2C) before reaching the allowable crack length.

The aging effects of thermal cycles on the 27 weld flaws have been projected to the end of the subsequent period of extended operation and are determined to remain below the allowable limit in accordance with 10 CFR 54.21(c)(ii).

A.4.3.8 Core Shroud Support Fatigue Analysis Reevaluation

The 40-year CUF values for the core shroud support are 0.17, per a GE Vessel stress and fatigue evaluated performed for the Extended Power Uprate (EPU). This reevaluation has been identified as a TLAA that requires evaluation for the subsequent period of extended operation.

The 80-year calculated CUF is 0.0730 and the CUF_{en} is 0.256, and both of these values are lower than the acceptance criterion of 1.0. The core shroud support fatigue analyses have been projected through the subsequent period of extended operation per 10 CFR 54.21(c)(1)(ii).

A.4.3.9 BFN Unit 3 Core Spray T-Box Repair Fatigue Evaluation

BFN Unit 3 has installed a core spray T-box repair. An explicit fatigue analysis was performed for this modification assuming a 40-year lifetime. For initial license renewal, the analysis was projected to 60 years. The fatigue usage factor was calculated under two different conditions: the core spray piping remained attached to the T-box; and the core spray piping completely separated from the T-box. Since this analysis was identified as a TLAA for the initial license renewal project and validated for 60 years, it has been identified as a TLAA that must be re-evaluated for the subsequent period of extended operation.

Inspections to date confirm that the piping remains attached to the T-box. Therefore, the relevant fatigue usage to be evaluated is that of the attached piping configuration. The fatigue usage for the Core Spray T-box repair has been conservatively projected to 80 years of plant operation with a calculated CUF of 0.044.

To ensure fatigue usage remains acceptable during the subsequent period of extended operation, ongoing inspections to ensure the Core Spray piping has not become detached and fatigue monitoring will be performed in accordance with 10 CFR 54.21(c)(iii).

A.4.3.10 BFN Unit 3 Core Spray Lower Line Section Replacement Fatigue Evaluation

A sectional replacement of the lower core spray sparger line was installed on BFN Unit 3. The repair is a bolted replacement of the lower section of the core spray piping in the downcomer region. For initial license renewal, the design life of this repair was specified as 40 years and would not exceed that lifetime before the end of the 60-year lifetime. Since this analysis was identified as a TLAA for the initial license renewal project and validated for 60 years, it has been identified as a TLAA that must be re-evaluated for the subsequent period of extended operation.

The fatigue usage for the lower line section replacement has been conservatively projected to 80 years of plant operation with a calculated CUF of 0.9. This is less than the allowable fatigue usage of 1.0, but ongoing inspections to ensure the Core Spray piping has not become detached and fatigue monitoring will need to be performed. This will ensure that fatigue usage remains acceptable during the subsequent period of extended operation, in accordance with 10 CFR 54.21(c)(iii).

A.4.3.11 Jet Pump to Core Shroud Support Plate Fatigue Evaluation

The BFN core shroud support plate and jet jump diffuser weld join the components and provides a barrier between the downcomer water and the jet pump flow. This a location where susceptibility to fatigue is a concern due to dynamic forces from jet pump flow and thermal stresses of the interfacing liquid temperature differences.

The fatigue usage for the JP Diffuser to Core Shroud Support Plate has been conservatively projected to 80 years of plant operation. The 80-year projected fatigue usage is 0.908. This is less than the allowable fatigue usage of 1.0, but ongoing inspections and fatigue monitoring will need to be performed. This will ensure that fatigue usage remains acceptable during the subsequent period of extended operation, in accordance with 10 CFR 54.21(c)(iii).

A.4.4 Environmental Qualification of Electric Equipment

A.4.4.1 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) for BFN. The NRC has established nuclear station environmental qualification (EQ) requirements in 10 CFR 50.49. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical components located in harsh plant environments are qualified to perform their safety function in those harsh environments after the effects of in-service aging. Harsh environments are defined as those areas of the plant that could be subject to the harsh environmental effects of a 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 Components program (A.3.1.3) will manage the effects of aging effects for the components associated with the environmental qualification through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii). The program meets the requirements of 10 CFR 50.49 for the applicable electrical components important to safety. Reanalysis of an aging evaluation to extend the qualifications of components 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 component 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 component if the reanalysis is unsuccessful.

The effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The Environmental Qualification of Electric Components program (A.3.1.3) has been demonstrated to be capable of programmatically managing the qualified lives of the electrical components falling within the scope of the program for subsequent license renewal in accordance with 10 CFR 54.21(c)(1)(iii).

A.4.5 Concrete Containment Tendon Prestress Analysis

The BFN containment does not have pre-stressed tendons. As such, this topic is not a TLAA.

A.4.6 Primary Containment Fatigue Analyses

A.4.6.1 Suppression Chambers, Vents and Downcomers Fatigue Analyses

Subsequent to the original design, elements of the BFN Unit 1, Unit 2, and Unit 3 primary containments were reanalyzed in response to discoveries, by General Electric and others, of unevaluated loads due to design basis events and Safety Relief Valve (SRV) discharge. The load definitions include assumed pressure and temperature transient cycles resulting from SRV discharge and design basis loss of coolant accident (LOCA) events. The BFN Torus Integrity Long-Term Program Plant Unique Analysis Report (PUAR) describes fatigue analyses of the suppression chamber and suppression chamber vents, including the vent headers and downcomers. The analyses assumed a limited number of main steam SRV actuations, based on plant data extrapolated to 40 years. Therefore, these analyses are TLAAs.

The estimated number of SRV actuations from initial startup through the end of the subsequent period of extended operation (80 total years of operation) is estimated to be approximately 190 for Unit 1, 318 for Unit 2, and 239 for Unit 3. It has been estimated for BFN, based on historical cycle tracking information, that the actual number of SRV actuations will not exceed 500 for Units 1, 2, and 3 during the subsequent period of extended operation.

The Fatigue Monitoring program (A.3.1.1) includes requirements that initiate corrective actions if a CUF value exceeds 70 percent of the ASME Section III acceptance criterion. Per 10 CFR 54.21(c)(1)(iii), the Fatigue Monitoring program is credited with managing these primary containment fatigue TLAAs through the subsequent period of extended operation.

A.4.6.2 Torus Attached Piping and Safety Relief Valve Discharge Lines Fatigue Analyses

There are 13 main steam Safety Relief Valve (SRV) to allow blowdown from the main steam piping in the drywell to the suppression pool via individual discharge lines passing through the main vents. The main steam SRV discharge piping enters the suppression chamber through penetrations in the suppression chamber vent header and the steam is discharged to the suppression pool water through a T-quencher attached to the suppression chamber.

The Plant Unique Analysis Report (PUAR) describes that a fatigue evaluation of the torus attached piping (TAP), including the main steam relief valve piping, was performed per a program developed by the Mark I Owner's Group. This analysis included the effects of mechanical load cycling in addition to the thermal expansion. The results justified fatigue life acceptability for TAP, including the SRV suppression chamber piping.

For the main steam relief valve discharge lines, T-quenchers, the main steam relief valve discharge line penetrations through the vent lines, torus attached piping systems, and the associated penetration locations, for Units 1, 2, and 3, the analysis remains valid for the subsequent period of extended operation as the estimated number of SRV actuations does not exceed 500.

For BFN Units 1, 2, and 3, the discussed analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.6.3 Containment Vent Lines and Process Penetration Bellows Fatigue Analyses

The suppression chamber vent line bellows are flexible expansion joints allowing movement of the main vent pipes through the suppression chamber wall while maintaining the required pressure boundary. The analysis of the suppression chamber bellows was performed in accordance with Standards of the Expansion Joint Manufacturers Association, Inc. as described in the PUAR. These analyses assume a limited number of thermal cycles throughout the 40-year life for the plant and are TLAAs.

For the subsequent period of extended operation, the number of thermal cycles for piping analyses would be proportionally increased to less than 2200, which is approximately 31% of the 7000-cycle threshold limit. The fatigue analyses for the subsequent period of extended operation were determined to remain valid for the 80-year plant life. The analyses remain valid through the subsequent period of extended operations in accordance with 10 CFR 54.21 (c)(1)(i).

A.4.7 Other Plant-Specific Time-Limited Aging Analyses

A.4.7.1 Reactor Building Crane Cyclic Loading Analyses

There is one 125-ton Reactor Building overhead crane with a 5-ton auxiliary hoist, which serves the three reactor units at BFN (FSAR Section 12.2.2.5). The Reactor Building overhead crane is designed to meet the applicable criteria and guidelines of Chapter 2-1 of ANSI B30.2-1976 and Crane Manufacturers Association of America (CMAA) Specification 70-1975 (FSAR Appendix C, Section C.8.4.1.7). For cyclic loading, CMAA 70 specifies that a crane classified as Service Class A1 is limited to 100,000 loading cycles (i.e., 100,000 lifts at rated capacity) over the design life.

Since the maximum number of load cycles over the life of a crane, specified in CMAA Specification 70, provides a basis for acceptability for fatigue over the life of a crane, these analyses are considered TLAAs that must be re-evaluated for the subsequent period of extended operation.

The resulting 80-year projected number of cycles for the Reactor Building overhead crane is less than 1903 rated capacity lift cycles and less than 84,145 lift cycles total. The 80-year projected number of lift cycles is less than the minimum allowable design value of 100,000 rated capacity lift cycles. Therefore, the Reactor Building overhead crane cyclic loading analysis remains valid for 80 years of plant operation in accordance with 10 CFR 54.21(c)(1)(i).

A.4.7.2 Radiation Degradation of Drywell Expansion Gap Foam Analysis

The steel drywell shell is enclosed in reinforced concrete for shielding purposes and to provide additional resistance to deformation and buckling of the drywell over areas where the concrete backs up the steel shell. Above the transition zone, the drywell is separated from the reinforced concrete by a gap of approximately 2 inches. This gap is filled with polyurethane foam. As described in FSAR Section 5.2.3.2, irradiation tests have shown that no change in the resilient characteristics will take place for exposures up to 1.0×10^8 Rads. The effect of a postulated increase in the foam stiffness resulting from radiation dose is a TLAA.

For the subsequent period of extended operation, the maximum dose after 80 years of operation and a design basis LOCA was less than the qualified dose of 1.0×10^8 Rads. Therefore, the polyurethane foam is projected to remain resilient for an 80-year license in accordance with 10 CFR 54.21(c)(1)(ii).

A.4.7.3 BFN Unit 2 Reactor Vessel Axial Weld Flaw

During BFN Unit 2 Refuel Outage 21 (U2R21) ultrasonic examination of the Unit 2 reactor vessel, an indication in a vertical weld (V-3-A) was identified that exceeds the acceptance standards of ASME Code, Section XI, IWB-3500. A flaw evaluation per the requirements of IWB-3600 was required.

Based on the flaw evaluation of the indication in the BFN Unit 2 reactor vessel V-3-A vertical weld using ASME Code Section XI, IWB-3600, it will take 84 years for the as-found flaw with an initial half depth of 1.6 inch to propagate to the allowable half-depth of 1.7156 inch based on the 64 EFPY fluence. Acceptable margin to the allowable flaw size should be verified as part of ongoing periodic inspections in accordance with ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (A.2.1.1).

The effects of aging on the intended function of the reactor vessel vertical weld V-3-A will be adequately managed through ongoing periodic ASME Code Section XI Inservice Inspections, per 10 CFR 54.21(c)(1)(iii).

A.5.0 Subsequent License Renewal Commitment List

Table A.5, Subsequent License Renewal Commitment List

No.	Program or Topic	Commitment	Implementation Schedule	Source
1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	The existing program is credited.	Ongoing.	Section A.2.1.1
2	Water Chemistry	The existing program is credited.	Ongoing.	Section A.2.1.2
3	Reactor Head Closure Stud Bolting	The existing program is credited and will be enhanced as follows: 1. Ensure the use of molybdenum disulfide (MoS_2) as a lubricant for reactor vessel closure studs is prohibited. 2. Revise implementing procedures to require that future replacement studs not be metal plated, the studs will use a bolting material for closure studs that has an actual measured yield strength less than 150 kilo-pounds per square inch (ksi) [1,034 megapascals (MPa)], and the replacement studs will have a manganese phosphate or other acceptable surface treatment. 3. Ensure repair and replacement be performed in accordance with the requirements of IWA-4000 and the material and inspection guidance of Regulatory Guide 1.65, Revision 1. The actual measured maximum yield strength of replacement material will be limited to 150 ksi as recommended in Regulatory Guide 1.65, Revision 1.	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.3
4	BWR Vessel ID Attachment Welds	The existing program is credited.	Ongoing	Section A.2.1.4

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
5	BWR Stress Corrosion Cracking	The existing program is credited and will be enhanced as follows: 1. Revise implementing procedures to explicitly state that the approved guidelines contained in BWRVIP-14-A, BWRVIP-59-A, BWRVIP-60-A, and BWRVIP-62 Revision 2 are used for evaluating crack growth in stainless, nickel alloys, and low-alloy steels. 2. Revise implementing procedures to explicitly state that, in accordance with NRC Generic Letter 88-01, repair of an IGSCC flaw, or an evaluation performed to accept a flaw must be approved by the NRC before resuming power operation. 3. Revise implementing procedures to explicitly state that corrective actions for stress corrosion cracking are performed in accordance with the guidance for replacement, weld overlay repair, and stress improvement provided in industry documents, including NRC Generic Letter 88-01, NUREG-0313 Revision 2, ASME Code, Section XI, Subsection IWA-4000, and approved Code Cases.	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.5
6	BWR Penetrations	The existing program is credited and will be enhanced as follows: 1. Revise implementing procedures to explicitly state that the approved guidelines contained in BWRVIP-53-A, BWRVIP-55-A, BWRVIP-57 Revision 1, and BWRVIP-58-A are used as a source of repair design criteria for reactor vessel internals components, as applicable.	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.6

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
7	BWR Vessel Internals	The existing program is credited and will be enhanced as follows: 1. Revise implementing procedures to explicitly state that the approved guidelines contained in BWRVIP-14-A, BWRVIP-59-A, BWRVIP-60-A, and BWRVIP-62 Revision 2 are used as a source of repair design criteria for reactor vessel internals components, as applicable. 2. Revise implementing procedures to implement BWRVIP-315-A and subsequent revisions approved by the NRC for BFN to use during the subsequent period of extended operation. 3. Revise implementing procedures to incorporate the requirement for justifying the frequency of subsequent inspections based on appropriate fracture toughness properties if component cracking is detected during inspection. 4. Revise implementing procedures to explicitly state that the approved guidelines contained in BWRVIP-14-A, BWRVIP-59-A, BWRVIP-60-A, BWRVIP-80-A and BWRVIP-99-A are used, as applicable, as a source of guidelines for evaluating crack growth in stainless steels, nickel alloys, and low-alloy steels, and that BWRVIP-100 Revision 2 is used as a source for flaw evaluation methodologies and fracture toughness data for SS core shroud exposed to neutron irradiation. 5. Revise implementing procedures to explicitly state that the guidelines contained in BWRVIP-97 Revision 1 are used as a source of guidelines for performing weld repairs to irradiated vessel internal components. 6. Revise implementing procedures to explicitly state that the guidelines in BWRVIP-84, Revision 3 (or a later revision if approved and issued) are used to provide guidance on procurement, design and welding requirements, fabrication limitations, and numerous other issues (including maintaining operating tensile stresses below a threshold limit that mitigates IGSCC) for the four specific material types used for in-vessel repairs: 300 Series austenitic stainless steel, Alloy X-750, Type XM-19 and Alloy 718. The resulting specification is then used for designing repairs to the following internal components that fall within the scope of the BWRVIP program: core shroud, shroud support, core spray, top guide, core plate, standby liquid control line, jet pumps, control rod drive components, instrument penetrations, and vessel brackets.	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.7

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
8	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program is a new condition monitoring program that will provide assurance that reactor coolant pressure boundary CASS components (i.e., pump casings) with the potential for significant thermal aging embrittlement meet their intended functions.	Program will be implemented no later than six months prior to the subsequent period of extended operation.	Section A.2.1.8
9	Flow-Accelerated Corrosion	The existing program is credited and will be enhanced as follows: 1. Ensure the management of wall thinning in screened-in components within the scope of SLR that are subject to erosion mechanisms in situations where periodic monitoring is used in lieu of elimination of the cause of various erosion mechanisms. 2. Ensure opportunistic visual inspections of up-stream and down-stream piping and components are performed during periodic pump and valve maintenance or during pipe replacements to assess internal surface conditions. 3. Reassess piping systems that have been excluded from wall thickness monitoring due to operation less than 2 percent of plant operating time (as allowed by NSAC-202L) to ensure the exclusion remains valid and applicable for operation beyond 60 years. If actual wall thickness information is not available for use in this reassessment, a representative sampling approach can be used. 4. For erosion mechanisms, ensure the identification of susceptible locations is based on the extent-of-condition reviews from corrective actions in response to plant-specific and industry OE. A combination of operating experience, results of prior inspections, engineering judgment and analysis will be used to select inspection locations. 5. For erosion mechanisms, ensure: • Trending of wall thickness measurements to adjust the monitoring frequency and to predict the remaining service life of the component for scheduling repairs or replacements is required; • Inspection results are evaluated to determine if assumptions in the extent-of-condition review remain valid;	Program will be enhanced no later than six months prior to the subsequent period of extended operation. The reassessment of exclusions will be completed no later than six months prior to the subsequent period of extended operation.	Section A.2.1.9

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
9	Flow-Accelerated Corrosion (continued)	• If degradation is associated with infrequent operational alignments, such as surveillances or pump starts/stops, then trending activities consider the number or duration of these occurrences; and • Periodic wall thickness measurements of replacement components may be required and should continue until the effectiveness of corrective actions has been confirmed. 6. For erosion mechanisms, ensure the effectiveness of long-term corrective actions is verified when long term corrective actions include elimination of the cause by adjusting operating parameters and/or changing components' geometric designs. Ensure periodic monitoring activities continue for any component replaced, due to erosion, with an alternate material, since a material that is completely resistant to erosion mechanisms is not available.		
10	Bolting Integrity	The existing program is credited and will be enhanced as follows: 1. Ensure the maximum yield strength of replacement or newly procured pressure-retaining bolting material is limited to an actual yield strength less than 150 ksi (1,034 MPa) to preclude or minimize loss of preload and cracking. 2. Revise implementing procedures to require periodic inspections of ASME Code Class 1, 2, and 3, and non-ASME Code class bolted joints for signs of leakage at least once per refueling cycle. 3. Revise implementing procedures to require sampling-based inspections to include a representative sample of 20 percent of the population of bolt heads and threads (defined as bolts with the same material and environment combination) or a maximum of 25 bolts per population at each unit per 10-year interval during the subsequent period of extended operation. Opportunistic inspections during maintenance activities may be credited during the same 10-year interval. 4. Revise implementing procedures to require, for all closure bolting greater than 2 inches in diameter (regardless of code classification) with actual yield strength greater than or equal to 150 ksi and closure bolting for which yield strength is unknown, performance of volumetric examination in accordance with ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1, is performed (i.e., acceptance standards, extent, and frequency of examination).	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.10

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
10	Bolting Integrity (continued)	5. Revise implementing procedures to establish the alternate methods of inspections of closure bolting in locations that preclude detection of joint leakage, as follows: • For systems containing air/gas, alternative inspections will include one or more of the following: (a) inspection consistent with that of submerged bolting; (b) visual inspection for discoloration when leakage from inside the piping system would discolor the external surfaces of the component; (c) monitoring and trending of pressure decay when the bolted connection is located within an isolated boundary; (d) soap bubble testing on the external mating surface of the bolted component; or (e) thermography, when the temperature of the process fluid is higher than ambient conditions around the component. • Alternative inspection of carbon steel submerged closure bolting on the RHRSW, HPFP and CCW pumps located at the Intake Channel will consist of visual inspections by divers and periodic vibration monitoring (measurement). Divers will inspect for degraded, visibly loose, missing, or broken bolts. Periodic (minimum semiannual) vibration monitoring of the pump/motor assembly will also be performed as an alternative inspection method. Increased vibration could be an indication of degradation of the pump casing upper flange bolted joint. Vibration readings will be trended. • For systems not normally pressurized, inspections for indication of leakage will be coordinated with scheduled operation of the system such as periodic surveillances. If system pressurization does not present the opportunity to perform the minimum required bolting inspections, then the visual inspections will be supplemented with torque checks to the extent that the bolting is not loose. 6. Revise implementing procedures for non-code closure bolting inspections to include methods for detecting aging effects and indications of joint leakage, as well as inspection parameters for items such as lighting, distance, and offset, which provide an adequate examination. 7. Revise implementing procedures to require, where practical, identified degradation to be projected until the next scheduled inspection. Results will be evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation.		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
10	Bolting Integrity (continued)	For sampling-based inspections, results will be evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation. 8. Revise implementing procedures to establish plant-specific acceptance criteria for alternative inspections or testing for submerged closure bolting or closure bolting where the piping systems contains air or gas for which leakage is difficult to detect, such as: soap bubble testing, thermography, monitoring of pressure decay, or torque checks to the extent that the bolting is not loose. 9. Revise implementing procedures to ensure that if a bolted connection for pressure-retaining components is reported to be leaking, follow-up periodic visual inspections will be conducted until the leak is corrected. If the leak rate is increasing, more frequent inspections are warranted. The effects of leakage from bolted connections that have an intended function identified in 10 CFR 54.4(a)(2) will be evaluated for its impact on components with an intended function identified in 10 CFR 54.4(a)(1) and located within the vicinity of the leaking bolted connection. 10. Revise implementing procedures, for sampling-based inspections, for a situation in which an acceptance criterion for allowable degradation is exceeded, and the aging effect causing the degradation for the material/environment combination is not corrected by repair or replacement, that additional inspections will be performed. The number of additional inspections will be determined in accordance with the Corrective Action Program; however, no fewer than five additional (or 20%, whichever is less) inspections will be performed of different components having the same material/environment/aging effect combination as the component(s) that did not meet the acceptance criterion. If these subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be performed to determine the further extent of inspections. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections for all BFN units' components having the same material, environment, and aging effect combination. The additional inspections will be completed within the same interval for which the original sample-based inspections are conducted. 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.		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
11	Open-Cycle Cooling Water System	The existing program is credited and will be enhanced as follows: 1. Revise implementing procedures to include heat exchangers in the High Pressure Fire Protection (Diesel Driven Pump) System, the Control Air System, and the Control Rod Drive System. 2. Revise implementing procedures to include reevaluation, repair, or replacement of components that do not meet minimum wall thickness requirements. If fouling is identified, the overall effect is evaluated for reduction of heat transfer, flow blockage, loss of material, and (if applicable) chemical treatment effectiveness. For ongoing degradation mechanisms (e.g., MIC), the frequency and extent of wall thickness inspections are increased commensurate with the significance of the degradation. 3. Revise implementing procedures to include the requirement that 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 inspections are conducted for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination will be inspected, whichever is less. The additional inspections include inspections at all BFN units with the same material, environment, and aging effect combination.	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.11

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
12	Closed Treated Water Systems (CTWS)	The existing program is credited and will be enhanced as follows: 1. Revise implementing procedures to manage the effects of cracking due to stress corrosion cracking in closed treated water systems. 2. Revise implementing procedures to include surface or volumetric examinations. The results of these examinations will be evaluated for surface discontinuities indicative of cracking. 3. Revise implementing procedures to include inspections of CTWS components for the detection of loss of material, cracking, and fouling. 4. Revise implementing procedures to include visual inspections of internal surfaces that are conducted whenever the system boundary is opened. At a minimum, in each 10-year period during the subsequent period of extended operation, a representative sample of 20 percent of the population (defined as components having the same material, water treatment program, and aging effect combination) or a maximum of 25 components per population at each unit will be inspected using techniques capable of detecting loss of material, cracking, and fouling, as appropriate. The 20 percent minimum is surface area inspected unless the component is measured in linear feet, such as piping. In that case, any combination of 1-foot length sections and components can be used to meet the recommended extent of 25 inspections. 5. Revise implementing procedures to include expansion of the sample population if degradation is identified in the initial population in order to determine the extent of the condition. 6. Revise implementing procedures to credit ongoing opportunistic visual inspections towards the representative samples for the loss of material and fouling; however, surface or volumetric examinations will be used to detect cracking. These inspections focus on the components most susceptible to aging due to time in service and severity of operating conditions, including locations where local conditions may be significantly more severe than those in the bulk water (e.g., heat exchanger tube surfaces).	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.12

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
12	Closed Treated Water Systems (CTWS) (continued)	7. Revise implementing procedures to include inspections and tests are performed by personnel qualified in accordance with applicable ASME code requirements. 8. Revise the implementing procedures to include if there are no ASME code requirements, inspections will be conducted in accordance with site procedures, which will include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. 9. Revise implementing procedures to include, where quantitative data is available, identified degradation to be projected until the next scheduled 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. 10. Revise implementing procedures to include, if one of the inspections does not meet acceptance criteria, the cause of the aging effect for each applicable material and environment to be either corrected by repair or replacement for all components constructed of the same material and exposed to the same environment or additional inspections will be conducted. The number of increased inspections will be determined in accordance with the site's Corrective Action Program; however, no fewer than five additional inspections will be conducted for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less. 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 ensure corrective actions appropriately address the associated causes. For BFN, the additional inspections will include inspections at all the units with the same material, environment, and aging effect combination.		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
13	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	The existing program is credited and will be enhanced as follows: 1. Revise the implementing procedures to ensure surface conditions are monitored by visual inspection to provide reasonable assurance that 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. 2. Revise the implementing procedures to ensure bolted connections are monitored by visual inspection to provide reasonable assurance that loss of material, cracking, and loose bolts, missing or loose nuts, and other conditions indicative of loss of preload are not occurring. 3. Revise implementation procedures to ensure aging effects will be detected for bridges, structural members, and structural components by visually inspecting for loss of material due to general corrosion; deformation; cracking, and wear. 4. Revise implementation procedures to ensure aging effects will be detected for bolted connections by visually inspecting for loss of material due to general corrosion; cracking; and loose or missing bolts or nuts, and other conditions indicative of loss of preload. 5. Revise implementation procedures to require visual inspection activities of in-scope load handling systems to be performed by qualified personnel. 6. Revise implementation procedures to ensure any visual indication of loss of material, deformation, or cracking, and any visual sign of loss of bolting preload will be evaluated for acceptance criteria according to ASME B30.2-1976 as well as other appropriate standards in the ASME B30 series including B30.11-1988, “Monorails and Underhung Cranes,” B30.16-1973, “Overhead Underhung and Stationary Hoists,” B30.10-1975, “Hooks,” and B30.17-1980, “Cranes and Monorails With Underhung Trolley or Bridge.” 7. Revise implementing procedures to ensure any repairs to in-scope load handling systems will be performed as specified in ASME B30.2-1976 as well as other appropriate standards in the ASME B30 series including B30.11-1988, B30.16-1973, B30.10-1975, and B30.17-1980.	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.13

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
14	Compressed Air Monitoring	The existing program is credited and will be enhanced as follows: 1. Revise implementing procedures to manage the aging effects of loss of material due to corrosion in compressed air system components located downstream of the compressed air system air dryers, or for components exposed to an internal gas environment (e.g., nitrogen-filled accumulators). 2. Revise implementing procedures for Compressed Air Monitoring Program to include the Emergency Diesel Generator Starting Air System. 3. Revise implementing procedures to incorporate guidelines for moisture and other corrosive contaminants limits based on ASME OM-2012, Division 2, Part 28, “Performance Testing of Instrument Air Systems in Light-Water Reactor Power Plants,” for inspection frequency and inspection methods. 4. Revise implementing procedures to include opportunistic visual inspections of accessible internal surfaces are performed for signs of corrosion and abnormal corrosion products that might indicate a loss of material within the system. 5. Revise implementing procedures to add opportunistic visual inspections of component internal surfaces exposed to an air-dry environment will be performed for signs of loss of material due to corrosion. 6. Revise implementing procedures to require qualification for personnel conducting visual inspection in accordance with site procedures. 7. Revise implementing procedures to ensure in-line dew point will be checked daily to determine whether moisture content is within the recommended range. 8. Revise implementing procedures to require trending of dew points being monitored and check for unusual trends in accordance with guidelines based on ASME OM-2012, Division 2, Part 28. 9. Revise implementing procedures to ensure that effects of corrosion are monitored by visual inspection. Test data are analyzed and compared to data from previous tests to provide for the timely detection of aging effects on passive components.	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.14

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
14	Compressed Air Monitoring (continued)	10. Revise implementing procedures to perform visual inspections which will ensure internal surfaces do not show signs of corrosion (general, pitting, and crevice) that could indicate the potential loss of function of the component. Suppliers' certifications can be used to demonstrate that bottled gases meet acceptable quality standards. 11. Revise implementing procedures to require corrective actions to be taken if any parameters, such as moisture content in the system air, are out of acceptable ranges, or if corrosion is identified on internal surfaces.		
15	Fire Protection	The existing program is credited and will be enhanced as follows: 1. Revise implementing procedures to require performance of a visual inspection by fire protection qualified personnel of not less than 10 percent of each type of seal in walkdowns performed at a frequency in accordance with the NRC-approved fire protection program or at least once every refueling outage. 2. Revise implementing procedures to require qualification for personnel conducting visual inspection in accordance with site procedures for fire seals, fire barrier walls, ceilings, floors, and doors (e.g., wear, missing parts); fire damper assemblies; and other fire barrier materials including structural steel fire proofing. 3. Revise implementing procedures to require performance of visual inspections of the surface condition of the fire barriers including structural steel fire proofing at a frequency in accordance with the BFN NFPA 805 Fire Protection Requirements Manual. 4. Revise implementing procedures to require that results of inspections of the aging effects of cracking and loss of material on fire barrier penetration seals, fire barriers, fire damper assemblies, and fire doors be trended to provide for timely detection of aging effects so that appropriate corrective actions be taken and: • Where practical, identified degradation is projected until the next inspection. • Results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation.	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.15

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
15	Fire Protection (continued)	• 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. 5. Revise implementing procedures to specify that inspection results are acceptable if there are no signs of degradation that could result in the loss of the fire protection capability due to loss of material. The specific acceptance criteria will include: • no visual indications (outside those allowed by approved penetration seal configurations) of cracking, separation of seals from walls and components, separation of layers of material, or ruptures or punctures of seals; • no significant indications of cracking and loss of material of fire barrier walls, ceilings, and floors and in other fire barrier materials; • no visual indications of missing parts, holes, and wear; • no visual indications of cracks or corrosion of fire damper assemblies; • no deficiencies in the functional tests of fire doors; and • no indications of excessive loss of material for the visual inspection of the carbon dioxide fire suppression system. 6. Revise implementing procedures to require, if any sign of degradation is detected (during the inspection of penetration seals) within that sample, the scope of the inspection will be expanded to include additional seals in accordance with the BFN Fire Protection Requirements Manual. In addition, if any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies will be adjusted to ensure the penetration seal's intended function is maintained until at least the performance of the next inspection.		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
16	Fire Water System	The existing program is credited and will be enhanced as follows: 1. Revise implementing procedures to ensure that flushes are in accordance with NFPA 25, 2011 Edition, section 7.3.2.1, to mitigate or prevent fouling, which can cause flow blockage or loss of material, by clearing corrosion products and sediment. 2. Revise implementing procedures to perform periodic flow tests, flushes, internal and external visual inspections, and testing of sprinklers systems. 3. Revise implementing procedures to ensure that, when visual inspections are used to detect loss of material, the inspection technique will be capable of detecting surface irregularities that could indicate an unexpected level of degradation due to corrosion and corrosion product deposition. Where such irregularities are detected, follow-up volumetric wall thickness examinations will be performed. Additionally, volumetric wall thickness inspections will be conducted on portions of water-based fire protection system components that are periodically subjected to flow but are normally dry. 4. Revise implementing procedures to ensure that visual examinations of cementitious materials will be conducted to detect indications of loss of material and cracking that could affect the system's ability to maintain pressure. 5. Revise implementing procedures to meet guidelines of Revision 0 of NUREG-2191, Table XI.M27-1, Fire Water System Inspection and Testing Recommendations (NFPA 25, 2011 Edition, Guidelines). 6. Revise implementing procedures to ensure visual inspections are capable of evaluating: (i) the condition of the external surfaces of components, (ii) the conditions of the internal surfaces of components that could indicate wall loss or cracking, and (iii) the inner diameter of the piping as it applies to the design flow of the fire protection system (i.e., to verify that corrosion product buildup has not resulted in flow blockage due to fouling). Internal visual inspections used to detect loss of material are capable of detecting surface irregularities that could be indicative of an unexpected level of degradation due to corrosion and corrosion product deposition. Where such irregularities are detected, follow-up volumetric examinations will be performed.	Program enhancements, associated with inspections/ tests required to be implemented prior to the subsequent period of extended operation, will be implemented prior to performance of the required inspections/tests. Remaining program enhancements will be implemented no later than six months prior to the subsequent period of extended operation. Inspections/tests that are to be completed prior to the subsequent period of extended operation will be completed no later than five years prior to the subsequent period of extended operation.	Section A.2.1.16

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
16	Fire Water System (continued)	7. Revise implementing procedures to ensure augmented tests and inspections are conducted on piping segments that cannot be drained or piping segments that allow water to collect: • In each 5-year interval, beginning 5 years prior to the subsequent period of extended operation, either conduct a flow test or flush sufficient to detect potential flow blockage, or conduct a visual inspection of 100 percent of the internal surface of piping segments that cannot be drained or piping segments that allow water to collect. • In each 5-year interval of the subsequent period of extended operation, 20 percent of the length of piping segments that cannot be drained or piping segments that allow water to collect is subject to volumetric wall thickness inspections. Measurement points are obtained to the extent that each potential degraded condition can be identified (e.g., general corrosion, microbiologically influenced corrosion). The 20 percent of piping that is inspected in each 5-year interval is in different locations than previously inspected piping. • If the results of a 100-percent internal visual inspection are acceptable, and the segment is not subsequently wetted, no further augmented tests or inspections are necessary. For portions of the normally dry piping that are configured to drain (e.g., pipe slopes towards a drain point) the tests and inspections of Revision 0 of NUREG-2191, Table XI.M27-1 do not need to be augmented. 8. Revise implementing procedures to require qualification for personnel conducting visual inspection in accordance with site procedures. The inspections and tests will follow site procedures that include inspection parameters for items such as lighting, distance, offset, presence of protective coatings, and cleaning processes. 9. Revise implementing procedures to ensure that results of flow testing (e.g., buried and underground piping, fire mains, and sprinkler), flushes, and wall thickness measurements are monitored and trended. Degradation identified by flow testing, flushes, and inspections will be evaluated.		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
16	Fire Water System (continued)	10. Revise implementing procedures to ensure that inspections with quantitative results, degradation identified will be projected until the next scheduled inspection. Results will be evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation. 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. 11. Revise implementing procedures to specify acceptance criteria for minimum design wall thickness, and for loose fouling products in systems that could cause flow blockage in the sprinklers or deluge nozzles. 12. Revise implementing procedures to ensure that if the presence of sufficient foreign organic or inorganic material to obstruct pipe or sprinklers is detected during pipe inspections, the material will be removed and the inspection results will be entered into the site's Corrective Action Program for further evaluation. 13. Revise implementing procedures to ensure 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 acceptance criteria due to current or projected degradation (i.e., trending) additional tests will be conducted. The number of increased tests will be determined in accordance with the site's corrective action process; however, there will be no fewer than two additional tests for each test that did not meet acceptance criteria. The additional inspections will be completed within the interval (i.e., 5 years, annual) in which the original test was conducted. If subsequent tests do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of tests. At BFN, the additional tests will include at least one test on one of the other units on site with the same material, environment, and aging effect combination. 14. Revise implementing procedures to ensure that an evaluation be conducted to determine if deposits need to be removed to determine if loss of material has occurred. When loose fouling products that could cause flow blockage in the sprinklers is detected, a flush will be conducted in accordance with the guidance in NFPA 25, 2011 Edition, Appendix D.5, “Flushing Procedures.” If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies will be adjusted as determined by the site's Corrective Action Program.		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
17	Outdoor and Large Atmospheric Metallic Storage Tanks	The existing program is credited and will be enhanced as follows: 1. Revise implementing procedures to require tank inspections of inside surfaces to be conducted in accordance with Table B.2.1.17-1, "Tank Inspection Recommendations," and the associated table notes. Table B.2.1.17-1 and the associated table notes will be added to the applicable procedure(s). The periodic inspections of the interior and bottom of the condensate storage tanks will manage the effects of corrosion on the intended function of these tanks. 2. Revise implementing procedures to require periodic visual inspections of tank exterior metallic surfaces to detect degradation at each outage, every two years, to confirm that paint and coatings are intact. 3. Revise implementing procedures to require volumetric inspections of the tank bottoms whenever the tank is drained, or at intervals in accordance with Table B.2.1.17-1, "Tank Inspection Recommendations," to determine potential loss of material of tank bottoms. Table B.2.1.17-1 and the associated table notes will be added to the applicable procedure(s). 4. Revise implementing procedures to note when inspections are conducted on a sampling basis, subsequent inspections are conducted in different locations unless the program states the basis for why repeated inspections will be conducted in the same location. 5. Revise implementing procedures to ensure volumetric inspections will be consistent with the ASME Code. All other inspections and testing are to follow site procedures that include inspection parameters for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. 6. Revise implementing procedures to require identified degradation, where practical, to be projected until the next scheduled inspection. 7. Revise implementing procedures to require results to be evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation.	Program enhancements will be implemented prior to beginning inspections within 10 years before the subsequent period of extended operation. The one-time inspections and initial periodic inspections are required to be performed within 10 years prior to the subsequent period of extended operation, and no later than 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.	Section A.2.1.17

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
17	Outdoor and Large Atmospheric Metallic Storage Tanks (continued)	8. Revise implementing procedures to require additional inspections to be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending). The number of increased inspections is determined in accordance with the site's corrective action process; however: • For inspections where only one tank of a material, environment, and aging effect was inspected, all tanks in that grouping will be inspected. • For other sampling based inspections (e.g., 20 percent, 25 locations) the smaller of five additional inspections or 20 percent of the inspection population is conducted. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause is conducted to determine the further extent of inspection. The additional inspections include inspections at all of the units with the same material, environment, and aging effect combination. • The timing of the additional inspections is based on the severity of the degradation identified and is commensurate with the potential for loss of intended function. However, with the exception of external visual inspections, the additional inspections are completed within the interval in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the 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. External visual inspections are conducted within the original refueling outage interval. • If any projected inspection results do not meet the acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the site's Corrective Action Program. However, for one time inspections that do not meet the acceptance criteria, inspections are subsequently conducted at least at 10 year inspection intervals.		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
18	Fuel Oil Chemistry	The existing program is credited and will be enhanced as follows: 1. Revise implementing procedures to require, for each Diesel Generator 7-Day Fuel Oil Tank and the Diesel Driven Fire Pump Fuel Oil Tank bottom surfaces, that UT inspections be performed at least once prior to the subsequent period of extended operation, at least once every 10 years during the subsequent period of operation, and if degradation is identified, UT examination of the tank bottom will be performed, the results analyzed and corrective actions taken, if necessary, to ensure integrity until the next scheduled inspection. 2. Revise implementing procedures to require, prior to the subsequent period of extended operation, performance of a one-time inspection of system components, exposed to diesel fuel oil, constructed of materials other than the steel in accordance with the BFN One-Time Inspection program (A.2.1.20). 3. Revise implementing procedures to require that results of inspections be trended to provide for timely detection of aging effects and, where practical, require that identified degradation be projected until the next inspection. 4. Revise implementing procedures to require that thickness measurements of each Diesel Generator 7-Day Fuel Oil Tank and the Diesel Driven Fire Pump Fuel Oil Tank bottom surfaces are evaluated against the design thickness and corrosion allowance. 5. Revise implementing procedures to require that corrective actions are taken to prevent recurrence when the specified limits for fuel oil standards are exceeded or when water is drained during periodic surveillance. If accumulated water is found in a fuel oil storage tank, it is immediately removed. In addition, when the presence of biological activity is confirmed, or if there is evidence of MIC, a biocide, in the form of a multi-function diesel fuel oil inhibitor may be added to fuel oil, or the fuel oil replaced.	Program will be enhanced no later than six months prior to the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.	Section A.2.1.18
19	Reactor Vessel Material Surveillance	The existing program is credited and will be enhanced as follows: 1. Implement BWRVIP-321 Revision 1-A to maintain compliance with 10 CFR 50 Appendix H during the subsequent period of extended operation.	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.19

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
20	One-Time Inspection	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 aging management program 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.	Program will be implemented prior to beginning inspections within 10 years before the subsequent period of extended operation. The inspections that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.	Section A.2.1.20
21	Selective Leaching	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 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 OE will be considered in the development and implementation of this program.	Program will be implemented prior to beginning inspections within 10 years before the subsequent period of extended operation. The inspections that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.	Section A.2.1.21

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
22	ASME Class 1 Small Bore Piping	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. For BFN, the program provides for a one-time inspection of a sample of the population of welds (butt welds and socket welds) and periodic inspections as required by the BFN ISI Program. Should evidence of cracking be revealed by a one-time inspection, the corrective actions will include examinations of additional ASME Code Class 1 small-bore piping welds to meet the intent of ASME Code, Section XI, Subarticle IWB-2430. If any new OE or evaluation of the one-time-examinations detect unacceptable flaws or relevant conditions, periodic examinations will be implemented in accordance with Category C of NUREG-2191, Revision 0, Table XI.M35-1.	Program will be implemented no later than six years prior to the subsequent period of extended operation. The one-time inspections are required to be performed within the six years prior to the subsequent period of extended operation, and no later than 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.	Section A.2.1.22
23	External Surfaces Monitoring of Mechanical Components	External Surfaces Monitoring of Mechanical Components program is a new condition monitoring program that will manage loss of material and cracking of metallic components, as well as loss of material, cracking, and hardening and loss of strength for elastomeric components, loss of preload for HVAC closure bolting, and reduced thermal insulation resistance. Periodic visual inspections, not to exceed a refueling outage interval, of metallic components, elastomers, and insulation jacketing (insulation when not jacketed) will be conducted.	Program will be implemented no later than six months prior to the subsequent period of extended operation.	Section A.2.1.23

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
24	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is a new condition monitoring program that will manage loss of material and cracking of metallic components, as well as loss of material and hardening and loss of strength of elastomeric materials. Reduction of heat transfer will also be managed. This program will consist of visual inspections of all accessible internal surfaces of piping, piping components, ducting, heat exchanger components, and other mechanical components.	Program will be implemented no later than six months prior to the subsequent period of extended operation.	Section A.2.1.24
25	Lubricating Oil Analysis	The Lubricating Oil Analysis program is a new condition monitoring program that provides reasonable assurance the oil environment in the mechanical systems is maintained to the required quality, and the oil systems are maintained free of contaminants (primarily water and particulates), thereby preserving an environment that is not conducive to loss of material or reduction of heat transfer. Testing activities include sampling and analysis of lubricating oil for detrimental contaminants. The presence of water or particulates may also indicate in-leakage and corrosion product buildup.	Program will be implemented no later than six months prior to the subsequent period of extended operation.	Section A.2.1.25
26	Monitoring of Neutron-Absorbing Materials Other Than Boraflex	The Monitoring of Neutron-Absorbing Materials Other Than Boraflex program is a new condition monitoring program that relies on periodic inspection, testing, monitoring, and analysis of test coupons of the neutron-absorbing material in the spent fuel storage racks to assure that the required 5% subcriticality margin is maintained. This program consists of inspecting the physical condition of the neutron-absorbing material, such as visual appearance, dimensional measurements, weight, geometric changes (e.g., bubbling, blistering, corrosion, pitting, cracking, and flaking), and boron areal density as observed from coupons, to monitor for reduction of neutron absorbing capacity, loss of material, and change in dimension.	Program will be implemented no later than six months prior to the subsequent period of extended operation.	Section A.2.1.26

Table A.5, Subsequent License Renewal Commitment List (Continued)

<table>
<tr><th>No.</th><th>Program or Topic</th><th>Commitment</th><th>Implementation Schedule</th><th>Source</th></tr>
<tr><td>27</td><td>Buried and Underground Piping and Tanks</td><td>The existing program is credited and will be enhanced as follows:
1. Revise implementing procedures to explicitly include the Condensate Demineralized Water System and the Radwaste System within the scope of the SLR Buried and Underground Piping and Tanks Aging Management Program.
2. Revise implementing procedures to require that the inspections of buried and underground piping be conducted in accordance with the below Table, with the inspections evenly distributed among the three BFN units, and include inspection of fittings (e.g., elbows, tees, etc.) to capture factory applied to field applied coating interfaces and the associated field applied coatings used at these locations. They will further require that the planned inspections of buried and underground piping and the associated field applied coatings used at these locations be conducted, as a minimum, by visual examination of the external surfaces of pipe or coatings.
<table><tr><th>Material</th><th>Environment</th><th>Number of Inspections</th><th>Notes</th></tr><tr><td>Steel</td><td>Soil/Buried</td><td>6</td><td>Category E - 6 inspections</td></tr><tr><td>Steel</td><td>Concrete</td><td>2</td><td>The concrete will be inspected for cracking, which could indicate piping degradation</td></tr><tr><td>Stainless Steel</td><td>Soil</td><td>2</td><td>None</td></tr><tr><td>Stainless Steel</td><td>Concrete</td><td>2</td><td>The concrete will be inspected for cracking, which could indicate piping degradation</td></tr></table>
There will be 6 inspections within the 10-year period prior to entry into the subsequent period of extended operation (SPEO), starting with the first 6 locations from Table B.2.1.27-1 and shown on Figure B.2.1.27-1 (Dig 1 through Dig 6). These inspections are in addition to any opportunistic inspections for this period. There will be 6 planned inspections for the first 10-year period of the SPEO and will be based on the next 6 locations from Table B.2.1.27-1 and shown on Figure B.2.1.27-1 (Dig 7 through Dig 12), however these locations may be adjusted based on OE from the inspections of the first 6 locations above or industry OE. These inspections will be in addition to any opportunistic inspections for this period. And then, based on the results of these 12 excavations and any opportunistic inspections or applicable OE, 6 additional locations will be selected and inspected for the last 10-year period of the SPEO.</td><td>Program will be enhanced prior to beginning inspections within 10 years before the subsequent period of extended operation.
Inspections, tests, and installation of coatings that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.</td><td>Section A.2.1.27</td></tr>
</table>

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
27	Buried and Underground Piping and Tanks (continued)	3. Revise implementing procedures to require that soil testing using the guidance in the EPRI Report 3002018353, Revision 2, “Buried and Underground Piping and Tank Reference Guide,” be conducted in conjunction with the periodic direct inspections of buried piping. 4. Revise implementing procedures to require that pipe inspection locations be determined based on factors including site OE, high-risk ranking (BPWORKS™), and indirect inspection results (soil analyses, close-interval surveys, and area potential earth current surveys), combined with results from pipe-to-soil potential surveys. Consideration is also given to characteristics such as coating type (i.e., material type), coating condition, backfill characteristics, soil resistivity, pipe contents, and pipe function. 5. Revise implementing procedures to require that opportunistic inspections be conducted for in-scope piping whenever they become accessible. 6. Revise implementing procedures to require that inspections in addition to those listed in the Table in Program Commitment Number 27.2 be performed, if appropriate, in response to plant-specific OE. 7. Revise implementing procedures to require that inspections be documented (including as-found and as-left inspection results). 8. Revise implementing procedures to require that inspections be performed by a qualified coatings inspector for evaluation of the condition of the coating. The coatings inspector will be qualified in accordance with TVA Nuclear Power General Engineering Specification G-55, Technical and Programmatic Requirements for the Protective Coating Program for TVA Nuclear Plants. Evaluation of coating failures and non-conforming conditions will be performed by a Coatings Subject Matter Expert, who is qualified via the completion of industry recognized formal coatings training, such as the EPRI Comprehensive Coatings Course and the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course, or equivalent courses as identified in NUREG-2191 AMP XI.M41 Section 6.a. 9. Revise implementing procedures to require that pipe-to-soil potential readings are acquired at the excavation and adjacent to the excavation location to determine the potential for galvanic corrosion cells and to assess the effectiveness of the coating system. Alternate pipe-to-soil potential measurement locations should be selected where excavation locations are in the immediate vicinity of previously performed pipe-to-soil potential readings.		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
27	Buried and Underground Piping and Tanks (continued)	Alternate pipe-to-soil potential measurement locations should be chosen to provide additional information applicable to selection of future excavation locations. A minimum of six pipe-to-soil potential readings should be acquired during each 10-year period (10 years prior to the SPEO and the first 10 years of the SPEO) and may be acquired anytime during the 10-year period of the scheduled dig (preferably prior to the actual excavation). 10. Revise implementing procedures to require that new and replacement field applied coating shall meet the guidance of Table 1 of NACE SP0169-2007. 11. Revise implementing procedures to require that new and replacement backfill shall meet the guidance of NACE SP0169-2007 Section 5.2.3. 12. Revise implementing procedures to require that backfill quality be demonstrated during the subsequent period of extended operation by examining the backfill while conducting the inspections of buried piping and by review of plant records. 13. Revise implementing procedures to revise the High Pressure Fire Protection System Ring Header Flow Test to (1) clarify that the test is being performed in accordance with Section 7.3 of NFPA 25 to satisfy the requirements of GALL-SLR AMP XI.M41 Element 2, Preventive Actions, Section 2.g.iii, Element 3, Parameters Monitored or Inspected, Section 3.f.i, and Element 4, Detection of Aging Effects, Section 4.e.i, (2) the frequency of the test will be increased to require at least one test be performed in each 1-year period during the subsequent period of extended operation, and (3) state that a reduction in available flow rate below the minimum required flow rate for the test will be used as an indication of possible fire main leakage. 14. Revise implementing procedures to require that results of periodic flow testing of fire mains in accordance with NFPA 25, which do not satisfy the minimum required flow rate for the test, to be considered as indication of possible fire main leakage and entered into the Corrective Action Program for trending and resolution. 15. Revise implementing procedures to state that flow test results for fire mains are acceptable if the results are in accordance with NFPA 25, Section 7.3.		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
27	Buried and Underground Piping and Tanks (continued)	16. Revise implementing procedures to require that visual inspections of the external surfaces of controlled low strength material backfill be performed, in place of the visual inspections of the external surface condition of buried piping and associated coatings, to detect potential cracks that could admit groundwater to the surface of the component. If alternatives to visual inspections are performed, they will be performed in accordance with NUREG-2191, Section XI.M41, Subsection 4.e. 17. Revise implementing procedures to require that monitoring of the surface condition of coatings and wraps will be conducted for all excavations of buried pipe to determine if the coatings and wraps are intact, well adhered, and otherwise sound such that aging effects would not be expected for the base material of the component. 18. Revise implementing procedures to require that monitoring of the surface condition of the underground piping and components be conducted to detect indications of aging effects such as general, pitting, crevice, and microbiologically influenced corrosion (MIC), and that the surface condition of the component be examined when it is exposed, such as when coating damage is discovered. 19. Revise implementing procedures to require that volumetric nondestructive examination techniques, or including the use of pit depth gages or calipers for measuring wall thickness, will have been determined to be effective for the material, environment, and conditions (e.g., remote methods) to be examined, and will be confirmed to be capable of quantifying general wall thickness and the depth of pits. 20. Revise implementing procedures to require that when coating damage is discovered and the pipe is found to be degraded, wall thickness measurements will be conducted to detect potential loss of material. 21. Revise implementing procedures to require that any inspections performed to identify cracking due to stress corrosion cracking for stainless steel materials will use a method that has been determined to be capable of detecting cracking. 22. Revise implementing procedures to clarify that coatings will not have to be removed that: (a) are intact, well-adhered, and otherwise sound for the remaining inspection interval; and (b) exhibit small blisters that are few in number and completely surrounded by sound coating bonded to the substrate.		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
27	Buried and Underground Piping and Tanks (continued)	23. Revise implementing procedures to require that inspections for cracking be conducted on piping with degraded coating to assess the impact of cracks on the pressure boundary function of the component being visually inspected. 24. Revise implementing procedures to require that BFN will take soil samples prior to planned excavations to confirm that the chemistry of the backfill is nonaggressive. 25. Revise implementing procedures to require that visual inspections be supplemented with surface and/or volumetric nondestructive testing if evidence of wall loss beyond minor surface scale is observed. 26. Revise implementing procedures to state that when conducting inspections of buried components embedded in concrete backfill or engineered flowable fill used as backfill, the backfill may be excavated and the pipe examined, or the soil around the backfill may be excavated and the cementitious material examined. Also state that the inspection will include excavation of the top surfaces and at least 50 percent of the side surface to visually inspect for cracks in the backfill that could admit groundwater to the external surfaces of the component. Additionally, require that when conducting inspection of backfill based on the number of inspections designated for that material type, 10 linear feet of the backfill be exposed for each inspection. 27. Revise implementing procedures to require that when plant-specific conditions result in transitioning to a higher number of inspections than originally planned at the beginning of a 10-year interval, the timing of the additional examinations will be based on the severity of the degradation identified and will be commensurate with the consequences of a leak or loss of function. However, in all cases, the expanded sample inspection will be completed within the 10-year interval in which the original inspection was conducted, or if this transition occurs in the latter half of the current 10-year interval, within 4 years after the end of the particular 10-year interval. Furthermore, these additional inspections conducted during the 4 years following the end of an inspection interval cannot also be credited towards the number of inspections required for the following 10-year interval. The number of inspections may be limited by the extent of piping subject to the observed degradation mechanism.		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
27	Buried and Underground Piping and Tanks (continued)	28. Revise implementing procedures to require that when conducting inspection of backfill based on the number of inspections designated for that material type, 10 linear feet of the backfill will be exposed for each inspection. 29. Revise implementing procedures to require that when piping inspections are based on the number of inspections in lieu of percentage of piping length, 10 feet of piping will be exposed for each inspection. Additionally, when the percentage of inspections for a given material type results in an inspection quantity of less than 10 feet, then 10 feet of piping will be inspected. Also, if the entire run of piping of that material type is less than 10 feet in total length, then the entire run of piping will be inspected. 30. Revise implementing procedures to state that opportunistic examinations of non-leaking pipes may be credited toward examinations if the location selection criteria are met. The use of guided wave ultrasonic examinations may not be substituted for the required inspections. 31. Revise implementing procedures to require that where wall thickness measurements are conducted, the results will be trended when follow up examinations are conducted. 32. Revise implementing procedures to explicitly require that, where practical, coating condition degradation will be projected until the next scheduled inspection, and that inspection/examination 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. 33. Revise implementing procedures, for coated piping, to require that there is either no evidence of coating degradation, or the type and extent of coating degradation is evaluated as insignificant by a Protective Coatings Subject Matter Expert who has completed industry recognized formal coatings training, such as the EPRI Comprehensive Coatings Course and the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course, or equivalent courses as identified in NUREG-2191 AMP XI.M41 Section 6.a.		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
27	Buried and Underground Piping and Tanks (continued)	34. Revise implementing procedures to require that measured wall thickness projected to the end of the subsequent period of extended operation meets minimum wall thickness requirements. 35. Revise implementing procedures to require that indications of cracking in metallic pipe be managed in accordance with the Corrective Action Program and require that indications of cracking in underground or buried in-scope piping be evaluated in accordance with applicable codes and plant-specific design criteria. 36. Revise implementing procedures to state that backfill is acceptable if the inspections do not reveal evidence that the backfill caused damage to the component's coatings or the surface of the component (if not coated). 37. Revise implementing procedures to state that cracks in cementitious backfill that could admit groundwater to the surface of the component are not acceptable. 38. Revise implementing procedures to require that where damage to the coating has been evaluated as significant and the damage was caused by nonconforming backfill, an extent of condition evaluation will be conducted to determine the extent of degraded backfill in the vicinity of the observed damage. 39. Revise implementing procedures to require that coated or uncoated metallic piping that is found to show evidence of corrosion will have the remaining wall thickness in the affected area determined to ensure that the minimum wall thickness is maintained. This may include different values for large area minimum wall thickness and local area wall thickness. If the wall thickness extrapolated to the end of the subsequent period of extended operation meets minimum wall thickness requirements, recommendations for expansion of sample size will not apply. 40. Revise implementing procedures to explicitly require that where the coatings, backfill, or the condition of exposed piping does not meet acceptance criteria, the degraded condition will be repaired, or the affected component will be replaced. In addition, where the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material is extrapolated to the end of the subsequent period of extended operation: • An expansion of sample size will be conducted. • The number of inspections within the affected piping categories will be doubled or increased by five, whichever is smaller.		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
27	Buried and Underground Piping and Tanks (continued)	• If the acceptance criteria are not met in any of the expanded samples, an analysis will be conducted to determine the extent of condition and extent of cause. • The number of follow-on inspections will be determined based on the extent of condition and extent of cause. • The expansion of sample inspections may be halted in a piping system or portion of system that will be replaced within the 10-year interval in which the inspections were conducted or, if identified in the latter half of the current 10-year interval, within 4 years after the end of the 10-year interval. 41. Require that the section of underground carbon steel piping (in an isolation valve pit) in the Hardened Containment Venting System which is not coated consistent with GALL-SLR Element 2 for underground steel piping, will be coated in accordance with Table 1 of NACE SP0169-2007 prior to the subsequent period of extended operation.		
28	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 aging management program is a new condition monitoring program that manages degradation of internal coatings/linings exposed to raw water, treated water, air, and condensation where loss of coating or lining integrity could prevent satisfactory accomplishment of any of the component's, or downstream component's, current licensing basis intended functions.	Program will be implemented prior to beginning inspections within 10 years before to the subsequent period of extended operation. Baseline inspections that are to be completed within 10 years prior to the subsequent period of extended operation will be completed no later than 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.	Section A.2.1.28

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
29	ASME Section XI, Subsection IWE	The existing program is credited and will be enhanced as follows: 1. Include the following components within the scope of the program: • dissimilar metal welds • bellows 2. 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, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” dated August 2014, will be used. 3. Revise implementing procedures to include monitoring of sand bed and refueling seal drains for water leakage on a weekly basis when the reactor cavity is filled with water. 4. Revise implementing procedures to include periodic monitoring to ensure the sand bed drains are kept clear to prevent moisture levels associated with accelerated corrosion rates in the exterior portion of the BWR Mark I steel containment drywell shell.	Program will be enhanced no later than six months prior to the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.	Section A.2.1.29

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
29	ASME Section XI, Subsection IWE (continued)	5. Revise implementing procedures to require a one-time volumetric examination of metal shell or liner surfaces that are inaccessible from one side, only if triggered by plant-specific operating experience. The trigger for this supplemental examination will be plant-specific occurrence or recurrence of measurable metal shell or liner corrosion (base metal material loss exceeding 10 percent 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 will consist 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 will be addressed in accordance with the applicable provisions of this aging management program. The sample size, locations, and any needed scope expansion (based on findings) for this one-time set of volumetric examinations will be determined on a plant-specific basis to demonstrate statistically with 95 percent confidence that 95 percent of the accessible portion of the containment liner is not experiencing corrosion degradation with greater than 10 percent loss of nominal thickness. Guidance provided in EPRI TR-107514 may be used for sampling considerations. 6. Revise implementing procedures to state the requirements of ASME Code Section XI, Subsection IWE and 10 CFR 50.55a are supplemented to perform surface examination (or other applicable technique) in addition to visual examinations, to detect cracking in stainless steel penetration sleeves, dissimilar metal welds, bellows, and steel components that are subject to cyclic loading but have no current licensing basis fatigue analysis. Containment integrated leak rate (Type A) tests and local leak rate (Type B) tests performed by the 10 CFR 50 Appendix J program (A.2.1.31) are credited for detection of cracking of dissimilar metal weld penetrations and penetration bellows, respectively, in lieu of supplemental surface examinations. 7. Revise implementing procedures to carry forward Commitment No. NCO040006088, Enhance ASME Section XI, Subsection IWE Program to perform a UT inspection of the sand bed area of the drywell liner of Units 1, 2, and 3. Subsequent periodic inspections will be performed on each unit prior to entry into the subsequent period of extended operation and at least once every 10 years thereafter.		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
29	ASME Section XI, Subsection IWE (continued)	8. Revise implementing procedures to include additional provisions to address identified degradation of weld pressure-retaining components that are subject to cyclic loading but do not have a fatigue analysis to undergo repair, rework, replacement, or justification for continued use by engineering evaluation. 9. Revise implementing procedures to specify the additional ASME Code subsections identified within IWE-3000 for addressing the following conditions: • Areas identified with damage or degradation that exceed acceptance standards require an engineering evaluation or require correction by repair or replacement, and • For the containment steel shell or liner, material loss locally exceeding 10 percent of the nominal containment wall thickness or material loss that is projected to locally exceed 10 percent of the nominal containment wall thickness before the next examination are documented. 10. Revise implementing procedures to require a causal analysis for instances when sources of moisture cannot be identified in the inaccessible area on the exterior of the containment drywell shell. 11. Revise implementing procedures to state that if moisture has been detected or suspected in the inaccessible area on the exterior of the containment drywell shell or the source of moisture cannot be determined subsequent to causal analysis, then: • Any components that are identified in the future as a source of moisture, will be added to the scope of SLR and if applicable, an aging management review will be performed. • Pursuant to Subsection IWE-1240, identify in the inspection program affected drywell surfaces requiring augmented examination for the subsequent period of extended operation in accordance with Table IWE-2500-1, Examination Category E-C. • Conduct augmented inspections of the identified drywell surfaces using examination methods that are in accordance with Subsection IWE-2500. • Demonstrate, through use of augmented inspections performed in accordance with Subsection IWE, that corrosion is not occurring or that corrosion is progressing so slowly that the age-related degradation will not jeopardize the intended function of the drywell shell through the subsequent period of extended operation.		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
30	ASME Section XI, Subsection IWF	The existing program is credited and will be enhanced as follows: 1. Implementing procedures will be revised to ensure the scope of this program includes support members, structural bolting, high-strength structural bolting [actual measured yield strength greater than or equal to 150 ksi (1,034 MPa)], anchor bolts, welds, support anchorage to the building structure, accessible sliding surfaces, constant and variable load spring hangers, guides, stops, and vibration isolation elements. 2. Implementing procedures will be revised to ensure the acceptability of inaccessible areas (e.g., portions of supports encased in concrete, buried underground, or encapsulated by guard pipe) will be evaluated when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. 3. Ensure the use of molybdenum disulfide (MoS_2) and other lubricants containing sulfur on structural bolting is prohibited. 4. Ensure preventive measures include, when replacement of bolting is required, using only bolting material that has actual measured yield strength less than 150 ksi (1,034 MPa) and for bolting replacement and maintenance activities include use of proper selection of bolting material and lubricants, and appropriate installation torque or tension, as recommended in Electric Power Research Institute (EPRI) documents (e.g., EPRI NP-5067 dated 1990 and EPRI TR-104213 dated December 1995), American Society for Testing and Materials (ASTM) standards, and American Institute of Steel Construction Specifications, as applicable.	Program will be enhanced no later than six months prior to the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.	Section A.2.1.30

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
30	ASME Section XI, Subsection IWF (continued)	5. Implementing procedures will be revised to ensure that if bolting within the scope of the program consists of ASTM A325 and/or ASTM A490 bolts (including respective equivalent twist-off type ASTM F1852 and/or ASTM F2280 bolts), the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” dated August 2014, will be used. 6. Ensure that parameters monitored or inspected include corrosion; cracking, deformation; misalignment of supports; missing, detached, or loosened support items; general structural condition of weld joints and weld connection to building structure for loss of integrity; improper clearances of guides and stops; and improper hot or cold settings of spring supports, and constant load supports. 7. Implementing procedures will be revised to ensure: accessible areas of sliding surfaces will be monitored for debris, dirt, or indications of excessive loss of material due to wear that could prevent or restrict sliding as intended in the design basis of the support; elastomeric or polymeric vibration isolation elements will be monitored for cracking, loss of material, and hardening; and bolting will be monitored for corrosion, loss of integrity of bolted connections due to self-loosening, and material conditions that can affect structural integrity. 8. Implementing procedures will be revised to ensure that high strength bolting (actual measured yield strength greater than or equal to 150 ksi (1,034 MPa) in sizes greater than 1 inch nominal diameter (including ASTM A490 bolts and ASTM F2280 bolts), will be monitored for SCC. 9. Implementing procedures will be revised to ensure that the provisions of ASME Code Section XI, 2007 Edition, 2008 Addenda, Subsection IWF are supplemented to include 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. The one-time inspection will be conducted within 5 years prior to entering the subsequent period of extended operation. The additional supports will be selected from the remaining population of IWF piping supports. However, the responsible engineer should ensure that the sample includes components that are most susceptible to age-related degradation (i.e., based on time in service, aggressive environment, etc.).		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
30	ASME Section XI, Subsection IWF (continued)	10. Ensure that the extent, frequency, and examination methods are designed to detect, evaluate, or repair age-related degradation before there is a loss of component support intended function. The VT-3 examination method specified by the program will be used to reveal loss of material due to corrosion and wear, cracks, verification of clearances, settings, physical displacements, loose or missing parts, debris or dirt in accessible areas of the sliding surfaces, or loss of integrity at bolted connections. 11. Implementing procedures will be revised to ensure: the VT-3 examination method specified by the program will be used to can also detect loss of material and cracking of elastomeric or polymeric vibration isolation elements; tactile inspection (feeling) of elastomeric or polymeric vibration isolation elements will be used to detect hardening if the vibration isolation function is suspect; and visual examinations that detect surface flaws which exceed acceptance criteria will be supplemented, in accordance with IWF-3200, by either surface or volumetric examinations to determine the character of the flaw. 12. Implementing procedures will be revised to ensure that for all high-strength bolting [actual measured yield strength greater than or equal to 150 ksi (1,034 MPa)] in sizes greater than 1 inch nominal diameter (including ASTM A490 and equivalent ASTM F2280), volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1 will be performed at least once per interval to detect cracking in addition to the VT-3 examination. In each 10 year period during subsequent period of extended operation, a representative sample of bolts will be inspected. The sample of high-strength bolts greater than 1 inch nominal diameter subject to volumetric examination will consist of 20% of the population (for a material/environment combination) up to a maximum of 25 bolts per unit. 13. Implementing procedures will be revised to ensure that if a component support does not exceed the acceptance standards of IWF-3400 but is repaired to as-new condition, the sample will be increased or modified to include another support that is representative of the remaining population of supports that were not repaired.		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
30	ASME Section XI, Subsection IWF (continued)	14. Implementing procedures will be revised to ensure the following conditions are identified as unacceptable in accordance with IWF-3410(a): • Loss of material, cracking, and hardening of elastomeric or polymeric vibration isolation elements that could reduce the vibration isolation function. The above conditions may be allowed to be accepted provided the technical basis for their acceptance is documented. 15. Ensure that identification of unacceptable conditions triggers an expansion of the inspection scope, in accordance with IWF-2430, and reexamination of the supports requiring corrective actions during the next inspection period, in accordance with IWF-2420(b). Additionally, in accordance with IWF-3122, ensure supports containing unacceptable conditions will be evaluated or tested or corrected before returning to service. Ensure corrective actions will be as delineated in IWF-3122.2. An alternative for evaluation or testing to substantiate structural integrity and/or functionality in accordance with IWF-3122.3 may also be used.		
31	10 CFR Part 50, Appendix J	The existing program is credited.	Ongoing	Section A.2.1.31
32	Masonry Walls	The existing program is credited and will be enhanced as follows: 1. Revise implementing procedures to address specific primary parameter monitored of cracking or loss of material at the mortar joints and gaps between the supports and masonry walls. 2. Revise implementing procedures to require inspection results to be documented and compared to previous inspections to identify changes or trends in the condition of masonry walls. 3. Revise implementing procedures to require identified degradation, where practical, to be projected until the next scheduled inspection. 4. Revise implementing procedures to require results to be evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation.	Program will be enhanced no later than six months prior to the subsequent period of extended operation.	Section A.2.1.32

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
32	Masonry Walls (continued)	5. Revise implementing procedures to ensure crack widths and lengths, and gaps between supports and masonry walls, that approach or exceed acceptance criteria are measured and assessed for trends. 6. Revise implementing procedures to encourage the use of photographs or surveys and to indicate photographic records may be used to document and trend the type, severity, extent and progression of degradation. 7. Revise implementing procedures to require each masonry wall that has observed degradation (e.g., shrinkage and/or separation, cracking of masonry walls, cracking or loss of material at the mortar joints and gaps between the supports and masonry walls) to be assessed against the evaluation basis to confirm that the degradation has not invalidated the original evaluation assumptions or impacted the capability to perform the intended functions. 8. Revise implementing procedures to require further evaluation to be conducted to determine if corrective action is required when the degradation is determined to impact the intended function of the wall or invalidate its evaluation basis. 9. Revise implementing procedures to require degraded conditions that exceed acceptance criteria and are accepted without repair or other corrective actions are technically justified or supported by an engineering evaluation. 10. Revise implementing procedures to adjust inspection frequencies ,as determined by the Corrective Action Program, If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection.		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
33	Structures Monitoring	The existing program is credited and will be enhanced as follows: 1. Revise implementing procedures to add the following structures to the scope: • Discharge Control Structure • Circulating Water Conduit • Low Level Radwaste (LLRW) Storage Facility • Supplemental Diesel Generator Building • Nitrogen Storage Tank Foundation • Radwaste/Condensate Water Storage Tanks Tunnels • Yard Structures, General • Structural Commodities: Hazard Barriers and Elastomers; Miscellaneous Steel; and Penetrations and Sleeves 2. 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, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” dated August 2014, will be used. 3. Revise implementing procedures to be consistent with ACI 349.3R-02 and SEI/ASCE 11-99 for selection of parameters to be monitored or inspected for concrete and steel structural elements and for steel liners, joints, coatings, and waterproofing membranes.	Program will be implemented no later than six months prior to the subsequent period of extended operation. Baseline inspections that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.	Section A.2.1.33

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
33	Structures Monitoring (continued)	4. Ensure inspections include the following indicators to identify cracking due to expansion from reaction with aggregates: • Surface aggregate popouts • Pattern cracking with darkened crack edges • Water ingress • Misalignment Inspections. 5. Revise implementing procedures to ensure steel, aluminum, and non-ferrous material components are monitored for cracking, loss of material due to corrosion or mechanical wear, and general degradation. 6. Revise implementing procedures to ensure accessible sliding surfaces will be monitored for indication of significant loss of material due to wear or corrosion, and for accumulation of debris or dirt. 7. Revise implementing procedures to ensure elastomeric vibration isolators, membranes, structural sealants, and seismic joint fillers are monitored for cracking, loss of material, hardening, separation and leakage. 8. Revise implementing procedures to include monitoring for earth berms for loss of material and loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, and seepage. 9. Revise implementing procedures to include monitoring of ground water chemistry for pH, chlorides, and sulfates on a frequency not to exceed five years that accounts for seasonal variances from locations that are representative of the groundwater in contact with the structures within the scope of this aging management program. Adverse results will be entered into the Corrective Action Program. 10. Revise implementing procedures to monitor and trend for signs of concrete or steel reinforcement degradation if through-wall leakage or groundwater infiltration is identified. 11. Revise implementing procedures that inspection of concrete structures, qualifications of inspection and evaluation personnel will be in accordance with ACI 349.3R-02.		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
33	Structures Monitoring (continued)	12. Revise implementing procedures to require indications of groundwater infiltration or through-concrete leakage to be assessed for aging effects. This may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels. When leakage volumes allow, assessments may include analysis of the leakage pH, along with mineral, chloride, sulfate, and iron content in the water. The responsible engineer for this program will also evaluate groundwater chemistry results that are sampled from locations representative of the water in contact with structures within the scope of subsequent license renewal. 13. Revise implementing procedures to state visual inspections may need to be enhanced or supplemented with nondestructive examination, destructive testing and/or analytical methods, based on the conditions observed or the parameter being monitored. 14. Revise implementing procedures to require visual inspection of elastomeric elements to be supplemented by tactile inspection to detect hardening if the intended function is suspect. 15. Revise implementing procedures to require the acceptability of inaccessible areas to be evaluated when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. The acceptability of inaccessible areas will also be assessed by examining representative samples of exposed portions of below grade concrete, when excavated for any reason. 16. Revise implementing procedures to establish quantitative baseline inspection data for structures and structural commodities for which baseline inspection data has not been established or for which the baseline acceptance criteria used are not comparable to the GALL-SLR acceptance criteria, prior to the subsequent period of extended operation. 17. Revise implementing procedures to require quantitative measurements and qualitative information to be recorded and trended for findings that exceed the acceptance criteria for all applicable parameters monitored or inspected.		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
33	Structures Monitoring (continued)	18. Ensure acceptance criteria for each structure and aging effect that are derived from BFN design basis documents, applicable codes and standards that include but are not limited to ACI 349.3R-02, SEI/ ASCE 11-99, or relevant AISC specifications and consider industry and plant operating experience. 19. Revise implementing procedures to ensure no evidence of popouts, map and pattern cracking with darkened crack edges, water ingress, and/or misalignment inspections; any evidence of these will require an engineering evaluation. 20. Revise implementing procedures to ensure no significant cracking, no significant loss of material due to corrosion or mechanical wear, and no significant signs of general degradation for steel, aluminum, and non-ferrous material components. 21. Revise implementing procedures to note loose bolts and nuts are not acceptable unless accepted by engineering evaluation for structural components within this aging management program. 22. Revise implementing procedures to add following acceptance criteria for structural steel bracing and edge supports associated with masonry block walls: • No adverse or significant deflection or distortion • No loose bolts (unless accepted by engineering evaluation) 23. Revise implementing procedures to require no signs of distress that could indicate degradation of the underlying material for painted or coated areas. 24. Revise implementing procedures to ensure there are no indications of excessive loss of material due to corrosion or wear and no debris or dirt that could restrict or prevent sliding of the surfaces as required by design. 25. Revise implementing procedures to ensure inspections for elastomeric vibration isolators, membranes, structural sealants, and seismic joint fillers the following acceptance criteria are met: • Elastomeric membranes, structural sealants, and seismic joint fillers are acceptable if the observed loss of material, cracking, hardening, separation, and/or leakage will not result in the loss of sealing. • Elastomeric vibration isolation elements are acceptable if there is no loss of material, cracking, hardening, separation, and/or leakage that could lead to the reduction or loss of isolation function.		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
33	Structures Monitoring (continued)	26. Revise implementing procedures to add following acceptance criteria for earth berms: • No significant loss of material • No significant loss of form • No evidence of erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, or seepage that could lead to a loss of material or form. 27. Revise implementing procedures to ensure the groundwater chemistry has been determined to be within the following parameters: pH > 5.5, chlorides < 500 ppm, and sulfates <1,500 ppm. Groundwater chemistry values indicative of aggressive groundwater/soil (pH < 5.5, chlorides > 500 ppm, or sulfates > 1,500 ppm) will be assessed for impact on concrete structural elements. This may include evaluations, destructive testing, and/or focused inspections of representative accessible (leading indicator) or below-grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil, on an interval not to exceed 5 years.		
34	Inspection of Water-Control Structures associated with Nuclear Power Plants	The existing program is credited and will be enhanced as follows: 1. Revise implementing procedures to add Circulating Water Conduits to the scope of the program. 2. Ensure preventive actions are included 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, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” dated August 2014, will be used. 3. Revise implementing procedures for monitoring and inspection of water-control concrete structures to also include those parameters as described in ACI 201.1R, these include cracking, movements (e.g., settlement, heaving, and deflection), conditions at junctions with abutments and embankments, loss of material, increase in porosity and permeability, seepage, and leakage.	Program will be implemented no later than six months prior to the subsequent period of extended operation. Baseline inspections that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.	Section A.2.1.34

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
34	Inspection of Water-Control Structures associated with Nuclear Power Plants (continued)	4. Revise implementing procedure to also include monitoring of the cool water and intake channels for sedimentation, debris, or instability of slopes that may impair the function of the canals under extreme low flow conditions. 5. Revise implementing procedure to include examinations of painted or coated areas for signs of distress that could indicate degradation of the underlying material. 6. Revise implementing procedure to include monitoring of bolting within the scope of the program for loss of material, loose bolts, missing or loose nuts, and other conditions indicative of loss of preload. In addition, concrete around anchor bolts is monitored for cracking. 7. Revise implementing procedures to examine representative samples of the exposed portions of the below-grade concrete when excavated for any reason. The acceptability of inaccessible areas will be evaluated when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. 8. Revise implementing procedures to ensure indications of groundwater infiltration or through-concrete leakage are assessed for aging effects. This may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels. When leakage volumes allow, assessments may include analysis of the leakage pH, along with mineral, chloride, sulfate and iron content in the water. 9. Revise implementing procedures to ensure submerged areas are monitored for indication of degradation with periodic inspections performed at intervals in accordance with the guidance in NRC Regulatory Guide 1.127 Revision 2. Submerged concrete structures may be inspected during periods of low tide, when dewatered, or with divers. 10. Ensure NRC Information Notice 2011-20, “Concrete Degradation by Alkali-Silica Reaction (ASR),” is referenced and add additional guidance for concrete inspections to identify indications of the presence of ASR. The additional guidance for these inspections of reinforced concrete, each inspection interval, include examination for pattern cracking with darkened crack edges, water ingress, and misalignment inspections. These inspection results will be evaluated by the responsible engineer each inspection cycle to identify changes that could be indicative of aging effects caused by reaction with aggregates. Such indications will be entered into the Corrective Action Program for evaluation.		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
34	Inspection of Water-Control Structures associated with Nuclear Power Plants (continued)	11. Ensure the guidance of NRC Regulatory Guide 1.127 Revision 2, for the compilation of engineering data collected from aging management program inspections is included. The use of photographs and surveys for comparison purposes of previous and current conditions as well as review of previous inspection records (baseline) may be used to identify new or progressive issues. Collected engineering data is reviewed by qualified engineering personnel to determine if changes fall outside the normal or expected conditions. 12. Ensure trending of quantitative measurements and qualitative information is required for findings exceeding acceptance criteria for applicable parameters monitored or inspected. 13. Revise implementing procedures to require quantitative baseline inspection data to be established in accordance with acceptance criteria prior to the subsequent period of extended operation. Previously performed inspections that were conducted using comparable acceptance criteria will be acceptable in lieu of performing a new baseline inspection. 14. Revise implementing procedures to require an engineering evaluation or the initiation of a Condition Report in the Corrective Action Program when any structural condition (including loose bolts, nuts, and degradation of piles and sheeting) is classified as “acceptable with deficiencies” or “unacceptable.” 15. Ensure acceptance criteria for inspections of earthen structures and canals shall ensure no significant loss of material or loss of form or evidence of erosion, settlement, frost action, waves, currents, surface runoff, or seepage, and ensure intake channel sedimentation is within design basis values		
35	Protective Coating Monitoring and Maintenance	The Protection Coating Monitoring and Maintenance program is a new program that ensures that the monitoring and maintenance program implemented in accordance with Regulatory Guide 1.54 is adequate for the subsequent period of extended operation The program consists of guidance for selection, application, inspection, and maintenance of protective coatings. 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. Degraded coatings in the containment are assessed periodically to ensure post-accident operability of the ECCS.	Program will be implemented no later than six months prior to the subsequent period of extended operation.	Section A.2.1.35

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
36	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	The existing program is credited and will be enhanced as follows: 1. Revise the implementing procedures to require review of plant-specific OE for previously identified and mitigated adverse localized environments cumulative aging effects applicable to in-scope cable and connection electrical insulation. 2. Revise the implementing procedures to require inspections for adverse localized environments for each of the most limiting cable and connection electrical insulation plant environments (e.g., caused by temperature, radiation, moisture, or contamination). 3. Revise the implementing procedures to require, during inspections, that cable and connection insulation be evaluated to confirm that aging related dispositioned corrective actions continue to support in-scope cable and connection intended functions during the subsequent period of extended operation. 4. Revise the implementing procedures to require the first inspection for subsequent license renewal to be completed prior to the subsequent period of operation. 5. Revise the implementing procedures to require that If visual inspections identify degraded or damaged conditions ,then testing may be performed for evaluation. For a large number of cables and connections identified as potentially degraded, a sample population is tested. The factors to be considered in the development of the cable and connection insulation sample representing approximately 20% of the in-scope population include: environment including identified adverse localized environments (high temperature, high humidity, vibration, etc.), voltage level, circuit loading, connection type, location, and insulation material. Additionally, the component sampling methodology will utilize a population that includes a representative sample of in-scope electrical cable and connection types regardless of whether or not the component was included in a previous aging management or maintenance program. The technical basis for the sample selection will be required to be documented. 6. Revise the implementing procedures to ensure acceptance criteria are met by conducting a review of test results or findings of surveillances of in-scope components. 7. Revise the implementing procedures to allow cable system testing, in accordance with applicable TVA procedures, as an alternative means for testing if visual inspections does not meet acceptance criteria.	Program will be enhanced no later than six months prior to the subsequent period of extended operation. Inspections and tests that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.	Section A.2.1.36

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
36	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (continued)	8. Revise the implementing procedures to require, when an unacceptable condition is identified, an evaluation to be performed to demonstrate that the condition will not adversely affect the affected component's ability to perform it's associated intended function for the time period being considered. The evaluation, including the technical basis, shall be documented. 9. Revise the implementing procedures to require a determination as to whether the same condition or situation is applicable to additional in-scope accessible and inaccessible cables or connections (extent of condition).		
37	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	The existing program is credited and will be enhanced as follows: 1. Revise the implementing procedures to include the in-scope portions of the Radiation Monitoring System listed in BFN SLRA Subsection 2.3.3.37. 2. Revise implementing procedures to include documented reviews of plant-specific OE for previously identified and mitigated adverse localized environments cumulative aging effects applicable to in-scope cable and connection electrical insulation. 3. Revise implementing procedures to include documented inspections for adverse localized environments for each of the most limiting cable and connection electrical insulation plant environments (e.g., caused by temperature, radiation, moisture, or contamination). 4. Revise the implementing procedures to include documentation of reviews of calibration, surveillance, and test results for the components within the scope of the program. 5. Revise the implementing procedures to include performance of cable tests for the components within the scope of the program when the calibration or surveillance program does not include the cabling system in the testing circuit, or as an alternative to the review of calibration results. 6. Revise implementing procedures to require trending of inspection and test results that are trendable and provide additional information on the rate of cable or connection degradation when age related degradation is suspected or found.	Program will be enhanced no later than six months prior to the subsequent period of extended operation. Reviews and tests that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.	Section A.2.1.37

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
37	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (continued)	7. Revise implementing procedures to ensure acceptance criteria are met by conducting a review of calibration results or findings of surveillances of in-scope components prior to the subsequent period of extended operation and at least once every 10 years. 8. Revise implementing procedures to allow cable system testing, in accordance with applicable TVA procedures, as an alternative means for testing if there is cable degradation when a calibration does not meet acceptance criteria.		
38	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	The existing program is credited and will be enhanced as follows: 1. Revise implementing procedures to specifically include splices present in medium-voltage cables in the scope of this aging management program. 2. Revise implementing procedures to require the performance of a one-time inspection and test of submarine or other cables designed for continuous wetting or submergence. Additional periodic tests and inspections for these cables will be determined by the one-time test/inspection results as well as industry and plant-specific OE. 3. Revise implementing procedures to require the inspection frequency for water accumulation to be established and adjusted based on plant-specific OE with cable wetting or submergence. 4. Revise implementing procedures to require the inspections for water accumulation to be performed after event driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding. 5. Revise implementing procedures to require dewatering systems (e.g., sump pumps and passive drains to be inspected and their operation verified periodically (annually). The periodic inspection will include documentation that either automatic or passive drainage systems or manually pumping are effective in preventing cable exposure to significant moisture.	Program will be enhanced no later than six months prior to the subsequent period of extended operation. Inspections and tests that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.	Section A.2.1.38

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
38	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (continued)	6. Revise implementing procedures to require that if water is found during inspection for water accumulation, the condition will be entered in the Corrective Action Program. The Corrective Action Program will specify and document the completion of actions taken to keep the cables free from significant moisture and to assess cable degradation. 7. Revise implementing procedures to require the first cable tests to be completed prior to the subsequent period of extended operation with additional tests to be performed at least once every 6 years thereafter. 8. Revise implementing procedures to require a BFN-specific inaccessible medium-voltage cable test matrix that documents inspection methods, test methods, and acceptance criteria for in-scope inaccessible medium-voltage power cables to be developed based on OE. 9. Revise implementing procedures to require visual inspections to be performed each time with the same inspection requirements (i.e., location, the manner inspected, etc.) such that the results can be compared to previous results for both immediate condition and long-term trend determinations. 10. Revise implementing procedures to require test results and associated trends to be evaluated against acceptance criteria to confirm that the timing of subsequent inspections and testing will maintain the components' intended functions throughout subsequent period of extended operation based on the projected rate of degradation.		

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
39	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 program is a new condition monitoring program that will manage the effects of reduced insulation resistance of non-EQ, in-scope, inaccessible (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations), instrument and control cables, exposed to significant moisture.	Program will be implemented no later than six months prior to the subsequent period of extended operation. One-time cable testing, initial manhole inspections, and initial visual cable inspections will be completed no later than 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.	Section A.2.1.39
40	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 aging management program is a new condition monitoring program that will manage the effects of reduced insulation resistance of non-EQ, in-scope, inaccessible (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations), low-voltage power cables (operating voltage less than 2 kV), exposed to significant moisture.	Program will be implemented no later than six months prior to the subsequent period of extended operation. One-time cable testing, initial manhole inspections, and initial visual cable inspections will be completed no later than 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.	Section A.2.1.40

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
41	Metal Enclosed Bus	The existing program is credited and will be enhanced as follows: 1. Revise implementing procedures to add the following to the scope of the program: • Start Bus 1A and 1B • Bus that connect the Unit Station Service Transformer 1A to the 4kV Common Board A • Bus between Start Bus 1A and 4kV Common Board A • Bus that connect the Unit Station Service Transformer 2A to the 4kV Common Board B • Bus between Start Bus 1B and 4kV Common Board B 2. Revise implementing procedures to require, for inaccessible Metal Enclosed Bus internal or external segments, documented engineering evaluation(s) to be performed to demonstrate that the inaccessible Metal Enclosed Bus segments evaluation, together with the accessible Metal Enclosed Bus inspection and test program, will continue to maintain the Metal Enclosed Buses consistent with the current licensing basis during the subsequent period of extended operation. These engineering evaluation(s) can be based on the results of accessible Metal Enclosed Bus inspections, tests, or other analyses. 3. Revise implementing procedures to require 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 or loss of strength. 4. Revise implementing procedures to require documented visual inspection of insulation material to detect surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination, when thermography or measuring connection resistance of accessible bolted connections covered with heat shrink tape, sleeving, insulating boots, etc., is not possible, to validate the absence of surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination.	Program will be enhanced no later than six months prior to the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.	Section A.2.1.41

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
41	Metal Enclosed Bus (continued)	5. Revise implementing procedures to require, when an alternative visual inspection is used to check Metal Enclosed Bus bolted connections, that the first inspection be completed prior to the subsequent period of extended operation and every 5 years thereafter. 6. Revise implementing procedures to require trending of inspection results that are trendable and provide additional information on the rate of degradation when age related degradation is suspected or found. 7. Revise implementing procedures to require all unacceptable thermography and/or visual inspections to be documented in a corrective action and subject to an engineering evaluation. 8. Revise implementing procedures to require that when an unacceptable condition or situation that is identified, (e.g., internal surface degradation including cracks, corrosion, foreign debris, excessive dust buildup, moisture intrusion, insulating material embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination), a determination to be made as to whether the same condition or situation is applicable to Metal Enclosed Bus bolted connections not inspected or tested. Further, when acceptance criteria are not met, a determination will be made as to whether the surveillance, inspection, or test, including frequency intervals, needs to be modified.		
42	Fuse Holders	The Fuse Holders program is a new condition monitoring program that will manage susceptibility to the following aging effects: increased resistance of connection due to chemical contamination, corrosion, and oxidation or fatigue caused by ohmic heating, thermal cycling, electrical transients, frequent removal and replacement, or vibration. The program also manages degradation of electrical insulation for the fuse holders with metallic clamps susceptible to the aging effects identified. Industry and plant-specific OE will be considered in the development and implementation of this program.	Program will be implemented no later than six months prior to the subsequent period of extended operation. Inspections and tests that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.	Section A.2.1.42

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
43	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 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 or periodically once every 5 years, if only visual inspection is used during the one-time test to provide an indication of the integrity of the cable connections.. The results will be evaluated to determine if there is a need for subsequent periodic testing on a 10-year frequency.	Program will be implemented no later than six months prior to the subsequent period of extended operation. Inspections and tests that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.	Section A.2.1.43
44	Fatigue Monitoring	The existing program is credited and will be enhanced as follows: 1. Revise implementing procedures to require monitoring of the Refueling Containment Skirt within the scope of the program. 2. Revise implementing procedures to require component locations that are in the scope of the program to be revised based on operating experience, plant modifications, and inspection findings. 3. Revise implementing procedures to ensure periodic review of chemistry parameters that give inputs to F_{en} factors used in CUF_{en} calculations for environmentally-assisted fatigue calculations. 4. Analysis has been completed to re-evaluate the cumulative fatigue limit for the recirculation inlet nozzle safe ends, and the limits will be revised in FatiguePro^{TM} prior to entry into the subsequent period of extended operation.	Program will be implemented no later than six months prior to the subsequent period of extended operation.	Section A.3.1.1 and Section 4.3.1 (for No.44.5)

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
44	Fatigue Monitoring (continued)	5. FatiguePro^{TM}, Version 4, will be implemented prior to entry into the subsequent period of extended operation. 6. Revise implementing procedures to provide for modifications to fatigue analyses or other corrective actions on an “as-needed” basis if assumed parameter values are approached, if transient severities exceed the design or assumed severities, if transient counts exceed the design or assumed quantities, if the definition of a transient is modified, if new transient events are identified, or if plant modifications to components change specified geometries. 7. Revise implementing procedures to reflect the re-evaluated cumulative fatigue values for the Units 1, 2, and 3 recirculation inlet nozzle safe ends. 8. Revise implementing procedures to require corrective actions for any locations projected to exceed a CUF or CUF_{en} of 1.0 during the subsequent period of extended operation, to include: • Repair or replacement of the component or • Provide a more rigorous analysis of the component to demonstrate that the CUF or CUF_{en} will not exceed 1.0 during the subsequent period of extended operation or • Perform a flaw tolerance analysis with appropriate (e.g., inclusion of environmental effects) crack growth rate curves and associated inspections performed in accordance with Appendix L of ASME Code Section XI. 9. Revise implementing procedures for CUF_{en} analyses projected to exceed a 1.0 during the subsequent period of extended operation, that scope expansion will included consideration of other locations with the highest expected CUF_{en} values.		
45	Neutron Fluence Monitoring	The Neutron Fluence Monitoring program is a new program that monitors and tracks increasing neutron fluence (integrated, time-dependent neutron flux exposures) to reactor vessel and reactor internal components to ensure that applicable reactor vessel neutron irradiation embrittlement analyses (i.e., TLAAs) and radiation-induced aging effect assessment for reactor internal components will remain within their applicable limits.	Program will be implemented no later than six months prior to the subsequent period of extended operation.	Section A.3.1.2

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
46	Environmental Qualification of Electric Equipment	The existing program is credited and will be enhanced as follows: 1. Revise implementing procedures to add activities to visually inspect accessible, passive EQ equipment located in adverse localized environments at least once every 10 years. The first periodic visual inspection will be performed prior to the subsequent period of extended operation. 2. Revise implementing procedures to establish acceptance criteria for the visual inspections of accessible, passive EQ equipment located in adverse localized environments.	Program will be enhanced no later than six months prior to the subsequent period of extended operation. Inspections and tests that are to be completed prior to the subsequent period of extended operation will be completed no later than 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.	Section A.3.1.3
47	Aging Management Review (Spent Fuel Pool Liner, Spent Fuel Pool Gates and associated Bolting)	Procedures will be revised to require periodic monitoring of spent fuel pool water level and leakage from the leak chase channels.	Procedure revisions will be implemented no later than six months prior to the subsequent period of extended operation.	Table 3.5.2-1
48	Quality Assurance Program	The existing program is credited and the BFN FSAR will be revised to require application of the TVA Nuclear Quality Assurance Plan elements of Corrective Action, Confirmation Process, and Administrative Controls to all AMPs credited for SLR, including programs for safety-related and nonsafety-related structures, systems, and components.	The BFN FSAR will be revised no later than six months prior to entering the subsequent period of extended operation.	Section A.1.4

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
49	Operating Experience Program	The existing program is credited and will be enhanced as follows: 1. An evaluation of operating experience at extended power uprate (EPU) levels will be performed to ensure that operating experience at EPU levels is properly addressed by the aging management programs. The evaluation will include BFN and other BWR plants operating at EPU levels. 2. Implementing procedures will be revised to require that training on age-related degradation and aging management be 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 operating experience.	The EPU operating experience evaluation will be completed no later than six months prior to entering the subsequent period of extended operation. Procedure revisions for age-related degradation and aging management training will be implemented and training completed no later than six months prior to entering the subsequent period of extended operation.	Section A.1.5
50	TLAA	License Amendment Requests for revision to BFN Technical Specifications Reactor Coolant System Pressure-Temperature Limits will be submitted to NRC to support issuance of License Amendments prior to entry into the subsequent period of extended operation.	The License Amendment Requests will be submitted to the NRC no later than 12 months prior to entering the subsequent period of extended operation.	Section 4.2.4
51	TLAA	Request for relief from circumferential weld examination will be submitted to NRC prior to entry into the subsequent period of extended operation.	The request for relief will be submitted no later than six months prior to entering the subsequent period of extended operation.	Section 4.2.5

Table A.5, Subsequent License Renewal Commitment List (Continued)

No.	Program or Topic	Commitment	Implementation Schedule	Source
52	TLAA	The BFN Unit 1 original core support plate plugs will be replaced prior to entry into the subsequent period of extended operation.	The replacement of the original core support plate plugs will be completed no later than six months prior to entering the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.	Section 4.2.13
53	Further Evaluation (Cracking Due to Stress Corrosion Cracking in Stainless Steel Alloys)	The BFN Unit 1, 2 and 3, Condensate/Demineralized Water System sample probes (1 per unit) will be permanently removed prior to entry into the subsequent period of extended operation.	Removal of the Condensate/ Demineralized Water System sample probes will be completed no later than six months prior to entering the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.	Section 3.4.2.2.2
54	Further Evaluation (Cracking Due to Stress Corrosion Cracking in Stainless Steel Alloys)	Three BFN Unit 2 Feedwater System sample probes will be inspected to ensure the design is consistent with the upgraded design for these sample probes. If any of these probes cannot be confirmed as being consistent with the upgraded design, the probe(s) will be replaced with upgraded design sample probes prior to entry into the subsequent period of extended operation.	Inspection and replacement, if required, of the Feedwater System sample probes will be completed no later than six months prior to entering the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.	Section 3.4.2.2.2

Appendix B - Aging Management Programs Table of Contents

Appendix B - Aging Management Programs

B.1.0 Introduction

B.1.1 Overview

Subsequent license renewal Aging Management Program (AMP) descriptions are provided in this appendix for each program credited for managing aging effects based upon the Aging Management Review (AMR) results provided in Sections 3.1 through 3.6 of this application.

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.

Credit has been taken for existing plant programs whenever possible. As such, programs and activities associated with a system, structure, component, or commodity grouping were considered. Existing programs and activities that apply to systems, structures, components, or commodity groupings were reviewed to determine whether they include the necessary actions to manage the effects of aging.

Existing plant programs may have been based on a regulatory commitment or requirement, or aging management activities credited for the initial license renewal, or a combination of both. Many of these existing programs included the required license renewal 10-element attributes, and have been demonstrated to adequately manage the identified aging effects. If an existing program did not adequately manage an identified aging effect, the program was enhanced as necessary. Occasionally, the creation of a new program was necessary.

B.1.2 Method of Discussion

For those AMPs that are consistent with the assumptions made in Sections X and XI of NUREG-2191, or are consistent with exceptions or enhancements, each program discussion is presented in the following format:

- A Program Description abstract of the overall program form and function is provided.
- A NUREG-2191 consistency statement is made about the program.

- Exceptions to the NUREG-2191 program are outlined and a justification for the exceptions is provided.
- Enhancements or additions to the BFN program are provided. Refer to Appendix A for implementation schedule information.
- Operating Experience (OE) information specific to the program is provided.
- A Conclusion section provides a statement of reasonable assurance that the program is effective, or will be effective when implemented, if new or enhanced.

B.1.3 Quality Assurance Program and Administrative Controls

The TVA Nuclear Quality Assurance Plan (NQAP) implements the requirements of 10 CFR 50, Appendix B and is consistent with the summary in Appendix A.2, “Quality Assurance For Aging Management Programs (Branch Technical Position IQMB-1)” of NUREG-2192. The scope of the TVA NQAP includes all systems, structures, and components (SSCs) that are safety related and also includes quality related programs and features that are important to continued reliable operation of TVA's nuclear facilities. The TVA NQAP elements of corrective action, confirmation process, and administrative controls will be applied to all Aging Management Programs (AMPs) credited for subsequent license renewal, including programs for safety-related and nonsafety-related structures, systems, and components. This is consistent with the approach applied for initial license renewal AMPs. The TVA NQAP includes the elements of corrective action, confirmation process, and administrative controls. Generically, the three elements are applicable as follows:

<u>Corrective Actions:</u>

A single Corrective Action Program is applied regardless of the safety classification of the system, structure, component, or commodity group. Corrective actions are implemented through the initiation of a Condition Report (CR) in accordance with the Corrective Action Program in place to meet the requirements of 10 CFR 50, Appendix B. The Corrective Action Program requires the initiation of a CR for actual or potential problems, including unexpected plant equipment degradation, damage, failure, malfunction, or loss of function. Documents that implement aging management programs for license renewal direct that a CR be prepared in accordance with those procedures whenever non-conforming conditions are found (i.e., the acceptance criteria are not met).

Equipment deficiencies are corrected through the Work Control Process in accordance with plant procedures. The Corrective Action Program specifies that a CR be initiated for condition identification, assignment of significance level and investigation class, investigation, corrective action determination, investigation report review and approval, action tracking, and trend analysis.

The Corrective Action Program implements the requirements of TVA-NQA-PLN89-A, TVA Nuclear Quality Assurance Plan, Section 10, “Adverse Conditions.” Specifically, conditions adverse to quality and significant conditions adverse to quality are resolved through direct action, the implementation of corrective actions, and where appropriate, the implementation of corrective actions to prevent recurrence.

<u>Confirmation Process:</u>

The focus of the confirmation process is on the follow-up actions that must be taken to verify effective implementation of corrective actions. The measure of effectiveness is in terms of correcting and precluding repetition of adverse conditions. The Corrective Action Program includes provisions for timely evaluation of adverse conditions and implementation of corrective actions required, including root cause determinations and prevention of recurrence where appropriate (e.g., significant conditions adverse to quality). The Corrective Action Program provides for tracking, coordinating, monitoring, reviewing, verifying, validating, and approving corrective actions, to ensure effective corrective actions are taken. The Corrective Action Program also includes monitoring for potentially adverse trends. The existence of an adverse trend due to recurring or repetitive adverse conditions results in the initiation of a CR. The aging management programs required for subsequent license renewal would also result in identification of related unsatisfactory conditions due to ineffective corrective action.

Since the same 10 CFR 50, Appendix B corrective actions and confirmation process is applied for nonconforming safety-related and nonsafety-related systems, structures, and components subject to AMR for subsequent license renewal, the Corrective Action Program is consistent with the NUREG-2191 AMP elements.

<u>Administrative Controls:</u>

The document control process applies to all generated 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, “Quality Assurance Requirements for Nuclear Power Plants and Fuel Reprocessing Plants.” Implementation is further defined in TVA-NQA-PLN89-A, TVA Nuclear Quality Assurance Plan, Section 6, “Control of Documents and Records.”

Administrative controls procedures provide information on procedures, instructions and other forms of administrative control documents, as well as guidance on classifying these documents into the proper document type and performance frequency. Revisions will be made to procedures and instructions that implement or administer aging management program requirements for the purposes of managing the associated aging effects for the subsequent period of extended operation.

B.1.4 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 Quality Assurance program, which meets the requirements of 10 CFR 50 Appendix B, and 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 OE program interfaces with and relies on active participation in the “Institute of Nuclear Power Operations” OE program, as endorsed by the NRC.

Operating experience is used at BFN to enhance plant programs, prevent repeat events, and prevent events that have occurred at other plants. As part of TVA, BFN personnel receive operating experience (internal and external to TVA) daily. TVA will enhance implementing procedures such that training on age-related degradation and aging management will be 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 operating experience. The OE process includes screening, evaluation, and acting on operating experience documents and information to prevent or mitigate the consequences of similar events. The OE process includes review of operating experience from external and internal sources. External operating experience includes Institute of Nuclear Power Operations documents, NRC documents (e.g., GALL Revisions, Information Notices, Regulatory Information Summaries, Interim Staff Guidance), and other documents (e.g., Licensee Event Reports, 10 CFR Part 21 Reports), as well as relevant research and development. Internal operating experience includes event investigations, trending reports, and lessons learned from in-house events as captured in program health reports, program assessments, and in the 10 CFR Part 50, Appendix B Corrective Action Program.

The TVA OE program that is implemented at BFN is an ongoing program that conforms to the recommendations of LR-ISG-2011-05, “Ongoing Review of Operating Experience,” and will be consistent with the expectations outlined in NUREG-2192, Appendix A.4, “Operating Experience for Aging Management Programs.” The systematic review of plant-specific and industry operating experience concerning aging management and age-related degradation ensures that the SLR AMPs are, and will continue to be, effective in managing the aging effects for which they are credited. Operating experience 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) aging management programs, to determine if changes to AMPs, or new AMPs are needed. The AMPs are either enhanced or new AMPs developed, as appropriate, when it is determined through the evaluation of operating experience that the effects of aging may not be adequately managed. AMPs are informed by the review of operating experience on an ongoing basis, regardless of the AMP’s implementation schedule. The TVA process directs the reporting of plant-specific operating experience on age-related degradation and aging management to the industry through the Institute of Nuclear Power Operations OE program, consistent with the guidance in NEI 14-13, “Use of Industry Operating Experience for Age-Related Degradation and Aging Management Programs.” In addition, the TVA process requires the periodic conduct of AMP effectiveness reviews, such that they are performed at least once within every five-year period, and refers to and is consistent with the guidance of NEI 14-12, “Aging Management Program Effectiveness.”

Each AMP summary in Appendix B of the SLRA contains a discussion of OE relevant to the program. This information was obtained through the review of internal OE captured by the Corrective Action Program, program assessments, program health reports, and through the review of external OE. Additionally, OE was obtained through interviews with system engineers, program engineers, and other plant personnel. New programs utilized internal and/or external operating experience as applicable, and the AMP summaries in Appendix B of the SLRA discuss the OE and associated corrective actions as they relate to implementation of the new program. The OE in each AMP summary identifies past corrective actions, some of 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 maintained during the subsequent period of extended operation.

Consistent with the guidance in Section 6 of Appendix B of NEI 17-01, “Industry Guideline for Implementing the Requirements of 10 CFR Part 54 for Subsequent License Renewal,” effectiveness reviews of initial license renewal aging management programs/activities (i.e., initial License Renewal AMPs) were performed, and are presented within the SLRA Appendix B AMP subsections that are most related to those initial License Renewal AMPs. For example, there were several initial License Renewal AMPs related to water chemistry control. An assessment of the effectiveness of these is presented within Section B.2.1.2, which describes the SLR AMP for the Water Chemistry aging management program. These effectiveness reviews are presented as the first OE example in the related SLRA AMP operating experience section (i.e., as OE #1). As applicable, these effectiveness review summaries may reveal such things as: 1) whether significant plant OE was identified due to AMP implementation, 2) whether significant relevant plant OE occurred that was not identified through AMP implementation, 3) how internal or external OE was used to inform or enhance the AMP, and 4) how the effectiveness of the AMP is being monitored.

B.1.5 NUREG-2191 Chapter XI Aging Management Programs

The following AMPs are described in the sections listed in this appendix. The programs are generic in nature as discussed in NUREG-2191, Section XI. NUREG-2191 Chapter XI programs are listed in Section B.2.1. All generic programs are fully consistent with or are, with identified exceptions, consistent with programs discussed in NUREG-2191. Programs are identified as either existing or new.

1. ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section B.2.1.1) [Existing]
2. Water Chemistry (Section B.2.1.2) [Existing]
3. Reactor Head Closure Stud Bolting (Section B.2.1.3) [Existing - Requires Enhancement - Includes Exception/Justification]
4. BWR Vessel ID Attachment Welds (Section B.2.1.4) [Existing - Includes Exception/ Justification]
5. BWR Stress Corrosion Cracking (Section B.2.1.5) [Existing - Requires Enhancement - Includes Exception/Justification]
6. BWR Penetrations (Section B.2.1.6) [Existing - Requires Enhancement - Includes Exception/ Justification]
7. BWR Vessel Internals (Section B.2.1.7) [Existing - Requires Enhancement - Includes Exceptions/Justifications]
8. Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (Section B.2.1.8) [New]
9. Flow-Accelerated Corrosion (Section B.2.1.9) [Existing - Requires Enhancement]
10. Bolting Integrity (Section B.2.1.10) [Existing - Requires Enhancement]
11. Open-Cycle Cooling Water System (Section B.2.1.11) [Existing - Requires Enhancement]
12. Closed Treated Water Systems (Section B.2.1.12) [Existing - Requires Enhancement]
13. Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (Section B.2.1.13) [Existing - Requires Enhancement]
14. Compressed Air Monitoring (Section B.2.1.14) [Existing - Requires Enhancement]
15. Fire Protection (Section B.2.1.15) [Existing - Requires Enhancement]

16. Fire Water System (Section B.2.1.16) [Existing - Requires Enhancement]
17. Outdoor and Large Atmospheric Metallic Storage Tanks (Section B.2.1.17) [Existing - Requires Enhancement - Includes Exception/Justification]
18. Fuel Oil Chemistry (Section B.2.1.18) [Existing - Requires Enhancement - Includes Exception/Justification]
19. Reactor Vessel Material Surveillance (Section B.2.1.19) [Existing - Requires Enhancement]
20. One-Time Inspection (Section B.2.1.20) [New]
21. Selective Leaching (Section B.2.1.21) [New]
22. ASME Code Class 1 Small-Bore Piping (Section B.2.1.22) [New]
23. External Surfaces Monitoring of Mechanical Components (Section B.2.1.23) [New]
24. Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section B.2.1.24) [New]
25. Lubricating Oil Analysis (Section B.2.1.25) [New]
26. Monitoring of Neutron-Absorbing Materials Other Than Boraflex (Section B.2.1.26) [New]
27. Buried and Underground Piping and Tanks (Section B.2.1.27) [Existing - Requires Enhancement - Includes Exceptions/Justifications]
28. Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (Section B.2.1.28) [New]
29. ASME Section XI, Subsection IWE (Section B.2.1.29) [Existing - Requires Enhancement]
30. ASME Section XI, Subsection IWF (Section B.2.1.30) [Existing - Requires Enhancement]
31. 10 CFR Part 50, Appendix J (Section B.2.1.31) [Existing]
32. Masonry Walls (Section B.2.1.32) [Existing - Requires Enhancement]
33. Structures Monitoring (Section B.2.1.33) [Existing - Requires Enhancement]
34. Inspection of Water-Control Structures Associated with Nuclear Power Plants (Section B.2.1.34) [Existing - Requires Enhancement]
35. Protective Coating Monitoring and Maintenance (Section B.2.1.35) [New]
36. Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.36) [Existing - Requires Enhancement]
37. Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (Section B.2.1.37) [Existing - Requires Enhancement]
38. Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.38) [Existing - Requires Enhancement]
39. Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.39) [New]
40. Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.40) [New]
41. Metal Enclosed Bus (Section B.2.1.41) [Existing - Requires Enhancement]

42. Fuse Holders (Section B.2.1.42) [New]
43. Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.43) [New]

B.1.6 NUREG-2191 Chapter X Aging Management Programs

The following NUREG-2191 Chapter X AMPs are described in Section B.3 of this appendix as indicated. Programs are identified as either existing or new.

1. Fatigue Monitoring (Section B.3.1.1) [Existing - Requires Enhancement]
2. Neutron Fluence Monitoring (Section B.3.1.2) [New]
3. Environmental Qualification of Electric Equipment (Section B.3.1.3) [Existing - Requires Enhancement]

B.2.0 Aging Management Programs

NUREG-2191 Aging Management Program Correlation

The correlation between the NUREG-2191 (Generic Aging Lessons Learned (GALL-SLR)) programs and the BFN Aging Management Programs (AMPs) is shown below. Links to the sections describing the BFN programs are provided.

NUREG-2191 Number	NUREG-2191 Program	BFN Program
XI.M1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (Section B.2.1.1)
XI.M2	Water Chemistry	Water Chemistry (Section B.2.1.2)
XI.M3	Reactor Head Closure Stud Bolting	Reactor Head Closure Stud Bolting (Section B.2.1.3)
XI.M4	BWR Vessel ID Attachment Welds	BWR Vessel ID Attachment Welds (Section B.2.1.4)
XI.M5	Deleted	Not applicable.
XI.M6	Deleted	Not applicable.
XI.M7	BWR Stress Corrosion Cracking	BWR Stress Corrosion Cracking (Section B.2.1.5)
XI.M8	BWR Penetrations	BWR Penetrations (Section B.2.1.6)
XI.M9	BWR Vessel Internals	BWR Vessel Internals (Section B.2.1.7)
XI.M10	Boric Acid Corrosion	Not Applicable. (BFN Units 1, 2, and 3 are BWRs)
XI.11B	Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components	Not Applicable. (BFN Units 1, 2, and 3 are BWRs)

NUREG-2191 Number	NUREG-2191 Program	BFN Program
XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (Section B.2.1.8)
XI.M16A	PWR Vessel Internals	Not Applicable. (BFN Units 1, 2, and 3 are BWRs)
XI.M17	Flow-Accelerated Corrosion	Flow-Accelerated Corrosion (Section B.2.1.9)
XI.M18	Bolting Integrity	Bolting Integrity (Section B.2.1.10)
XI.M19	Steam Generators	Not Applicable. (BFN Units 1, 2, and 3 are BWRs)
XI.M20	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System (Section B.2.1.11)
XI.M21A	Closed Treated Water Systems	Closed Treated Water Systems (Section B.2.1.12)
XI.M22	Boraflex Monitoring	Not Applicable. (This program is not credited for aging management. The neutron-absorbing material in the BFN spent fuel pool racks does not include Boraflex.)
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 (Section B.2.1.13)
XI.M24	Compressed Air Monitoring	Compressed Air Monitoring (Section B.2.1.14)
XI.M25	BWR Reactor Water Cleanup System	Not Applicable. GALL-SLR AMP XI.M25, BWR Reactor Water Cleanup System, will not be used since BFN Units 1, 2, and 3 have satisfactorily completed all actions requested in NRC Generic Letter 89-10 and NRC Generic Letter 88-01 for the Reactor Water Cleanup (RWCU) System. NRC has documented closeout of these Generic Letters for BFN. In addition, the RWCU piping on each unit has been replaced with piping made of material that is resistant to IGSCC. Therefore, consistent with NRC guidance, no IGSCC inspections are required.
XI.M26	Fire Protection	Fire Protection (Section B.2.1.15)
XI.M27	Fire Water System	Fire Water System (Section B.2.1.16)
XI.M29	Outdoor and Large Atmospheric Metallic Storage Tanks	Outdoor and Large Atmospheric Metallic Storage Tanks (Section B.2.1.17)
XI.M30	Fuel Oil Chemistry	Fuel Oil Chemistry (Section B.2.1.18)
XI.M31	Reactor Vessel Material Surveillance	Reactor Vessel Material Surveillance (Section B.2.1.19)
XI.M32	One-Time Inspection	One-Time Inspection (Section B.2.1.20)
XI.M33	Selective Leaching	Selective Leaching (Section B.2.1.21)

NUREG-2191 Number	NUREG-2191 Program	BFN Program
XI.M35	ASME Class 1 Small Bore Piping	ASME Class 1 Small Bore Piping (Section B.2.1.22)
XI.M36	External Surfaces Monitoring of Mechanical Components	External Surfaces Monitoring of Mechanical Components (Section B.2.1.23)
XI.M37	Flux Thimble Tube Inspection	Not Applicable. (BFN Units 1, 2, and 3 are BWRs)
XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (Section B.2.1.24)
XI.M39	Lubricating Oil Analysis	Lubricating Oil Analysis (Section B.2.1.25)
XI.M40	Monitoring of Neutron-Absorbing Materials Other Than Boraflex	Monitoring of Neutron-Absorbing Materials Other Than Boraflex (Section B.2.1.26)
XI.M41	Buried and Underground Piping and Tanks	Buried and Underground Piping and Tanks (Section B.2.1.27)
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 (Section B.2.1.28)
XI.S1	ASME Section XI, Subsection IWE	ASME Section XI, Subsection IWE (Section B.2.1.29)
XI.S2	ASME Section XI, Subsection IWL	Not Applicable. (BFN Units 1, 2, and 3 do not have reinforced prestressed concrete containments)
XI.S3	ASME Section XI, Subsection IWF	ASME Section XI, Subsection IWF (Section B.2.1.30)
XI.S4	10 CFR Part 50, Appendix J	10 CFR Part 50, Appendix J (Section B.2.1.31)
XI.S5	Masonry Walls	Masonry Walls (Section B.2.1.32)
XI.S6	Structures Monitoring	Structures Monitoring (Section B.2.1.33)
XI.S7	Inspection of Water-Control Structures associated with Nuclear Power Plants	Inspection of Water-Control Structures associated with Nuclear Power Plants (Section B.2.1.34)
XI.S8	Protective Coating Monitoring and Maintenance	Protective Coating Monitoring and Maintenance (Section B.2.1.35)
XI.E1	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.36)
XI.E2	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (Section B.2.1.37)

NUREG-2191 Number	NUREG-2191 Program	BFN Program
XI.E3A	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.38)
XI.E3B	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.39)
XI.E3C	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.40)
XI.E4	Metal Enclosed Bus	Metal Enclosed Bus (Section B.2.1.41)
XI.E5	Fuse Holders	Fuse Holders (Section B.2.1.42)
XI.E6	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (Section B.2.1.43)
XI.E7	High-Voltage Insulators	Not applicable. (BFN High-Voltage Insulators have no aging effects requiring management.)
X.M1	Fatigue Monitoring	Fatigue Monitoring (Section B.3.1.1)
X.M2	Neutron Fluence Monitoring	Neutron Fluence Monitoring (Section B.3.1.2)
X.S1	Concrete Containment Unbonded Tendon Prestress	Not Applicable. (BFN Units 1, 2, and 3 do not have containments with prestressed tendons)
X.E1	Environmental Qualification of Electric Equipment	Environmental Qualification of Electric Equipment (Section B.3.1.3)

B.2.1 NUREG-2191 Chapter XI Aging Management Programs

This section provides summaries of the NUREG-2191 programs credited for managing the effects of aging.

B.2.1.1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

Program Description

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program is an existing condition monitoring program which manages the aging effects of cracking, loss of material, and loss of fracture toughness in Class 1, 2, and 3 piping and components. This program includes periodic visual, surface, and volumetric examination of Class 1, 2, and 3 pressure-retaining components. The program implements the Inservice Inspection (ISI) requirements of ASME Code, Section XI, for Class 1, 2, and 3 pressure-retaining components and their integral attachments. Examination of these components is in accordance with Subsections IWB, IWC, and IWD respectively.

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program implements the required component examination schedule per ASME 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 Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1. The examination methods specified in Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1 are based on approved industry standards for detecting degradation of components. Inspection results are evaluated by qualified individuals in accordance with ASME Code Section XI acceptance criteria. Indications and relevant conditions detected during examinations are entered into the Corrective Action Program and evaluated in accordance with ASME 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 conformance with IWA-4000.

For the current 10-year inspection intervals for each of the three BFN units, the ISI program applies the requirements of ASME Code, Section XI, 2007 Edition through 2008 Addenda. The program also utilizes NRC approved alternatives, relief requests and ASME Code Cases listed in NRC Regulatory Guide 1.147 that also remain in effect until the end of the interval. In accordance with 10 CFR 50.55a(g)(4), the ISI program is updated each successive 120-month inspection interval to comply with the requirements of the latest edition of the ASME Code specified 18 months before the start of the inspection interval. Any deviation from ASME Code, Section XI requirements must be approved by the NRC per a relief request, alternate request or ASME Code Case.

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program includes all component inspection activity 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 (B.2.1.3)
- BWR Vessel ID Attachment Welds (B.2.1.4)
- BWR Stress Corrosion Cracking (B.2.1.5)
- BWR Penetrations (B.2.1.6)

- BWR Vessel Internals (B.2.1.7)
- ASME Code Class 1 Small-Bore Piping (B.2.1.22)

NUREG-2191 Consistency

The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD is consistent with the 10 elements of aging management program XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for the ASME Section XI Inservice Inspection Subsections IWB, IWC, and IWD program described in FSAR Section O.1.4 in support of preparing the BFN Subsequent License Renewal Application. The purpose of the program effectiveness review was to verify that the management of the aging effects of cracking, loss of material, loss of fracture toughness, and loss of preload for pressure-retaining bolting of Class 1, 2, and 3 pressure-retaining components and their integral attachments in accordance with the requirements of 10 CFR 50.55a and the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code are being effectively implemented in the initial license renewal period of extended operation. The original activities included periodic visual, surface, and/or volumetric examination of Class 1, 2, and 3 pressure-retaining components and their integral attachments. The program effectiveness review was comprised of a review of testing results and review of the Owners Activity Report submitted to the NRC following each refueling outage. The Owners Activity Report details inspections performed and any degradation needing evaluation or repair. A review of Owners Activity Report for all unit outages from 2017 through 2022 show no indications which would cause a loss of License Renewal intended function. Deficiencies identified in the Owners Activity Report were entered into the Corrective Action Program and were evaluated and corrective actions developed and taken to resolve the identified issue. The following two examples of using the corrective action program is as follows:
   - A weld indication was identified during Unit 2 Refueling Outage 21 in 2021 and entered into the Corrective Action Program and evaluated. The results of the evaluation determined that the observed indication is acceptable for continued operation per the requirements of ASME Code, Section XI, IWB-3640 and Appendix A. Limits were established bounding the evaluation and follow up inspections will be performed.
   - A weld flaw was identified during the Unit 1 Refueling Outage 13 in 2020 and entered into the Corrective Action Program and evaluated. An evaluation of the flaw indicated that a weld overlay repair was required. This repair was completed in 2022. This weld is

inspected every refueling outage, and therefore will continue to be evaluated for any additional degradation.

This operating experience provides objective evidence that inspections are performed, and the Corrective Action Program effectively manages aging effects in the ASME Section XI Inservice Inspection Subsections IWB, IWC, and IWD program to assure that they will be able to continue to perform their intended functions and that continued implementation of the program will assure degraded conditions will be identified and corrected during the subsequent period of extended operation.

2. A review of the revisions made to the implementing inspection procedure was conducted. This review indicates that there are frequent revisions. For example, there have been 10 revisions between 2018 and 2022 to implementing procedure for the Inservice Inspection Program. Revisions were made to add new components to the program because of plant design changes, and to coordinate inspections in the appropriate inspection periods. For example, revisions made in 2018 and 2019 added viscoelastic damper inspections to the procedures due to a plant modification for Extended Power Uprate. Also, a revision was made in 2019 to Unit 1, 2, and 3 Inservice Inspection/Augmented Inservice Inspection scope to align with examinations performed during the 1st period, and another in 2020 to move Core Spray Risk Informed welds from 3rd period to 2nd period, and two Main Steam Risk Informed welds from 2nd period to 3rd period. This change in inspection periods was to support weld exams during the same outage.

   This operating experience provides objective evidence that the program implementing procedures are maintained and updated as needed to support a healthy program. Continued implementation of the program will assure that components in the ASME Section XI Inservice Inspection Subsections IWB, IWC, and IWD program will be able to continue to perform their intended functions and that appropriate aging management will be performed during the subsequent period of extended operation.

3. Multiple audits by the site Quality Assurance organization have been conducted on the program. Examples include Site Audits performed in June of 2016 and in June on 2018. These audits identified minor recommended administrative enhancements. These recommendations were entered into the Corrective Action Program for resolution.

   This operating experience provides objective evidence that program evaluations are used to identify deficient conditions in the program, and for the Correct Action Program to correct those conditions, to assure that components in the ASME Section XI Inservice Inspection Subsections IWB, IWC, and IWD Program will be able to continue to perform their intended functions and that appropriate aging management will be performed during the subsequent period of extended operation.

Conclusion

The ASME Section XI Inservice Inspection, Subsections IWB, IWC and IWD program provides reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.2 Water Chemistry

Program Description

The BFN Water Chemistry aging management program is an existing program whose activities mitigate the loss of material due to corrosion, cracking due to stress cracking (SCC) and related mechanisms, and reduction of heat transfer due to fouling in components exposed to a reactor coolant, steam, or treated water environment. The program includes periodic monitoring and trending of the treated water and control of known detrimental contaminants such as conductivity, chloride, and sulfate concentrations within the guidelines of the Boiling Water Reactor Vessel and Internals Project BWRVIP-190, BWR Vessel and Internals Project: BWR Water Chemistry Guidelines, Revision 1, to minimize loss of material or cracking.

The BFN Water Chemistry program consists of monitoring and controlling the chemical environments of those systems that are exposed to reactor water, steam, condensate, feedwater, control rod drive water, demineralized water, torus water, and spent fuel pool water, such that aging effects of system components are minimized in accordance with BWRVIP-190, Revision 1. Sampling frequencies, action limits for each control parameter, and corrective actions are defined in specific procedures. Conditions that do not meet acceptance criteria are evaluated in accordance with the Corrective Action Program.

Major component types managed by this program include the reactor vessel, reactor internals, piping, piping elements, heat exchangers, and tanks. Reactor water, condensate, control rod drive water, feedwater, demineralized water storage tank water, torus water, spent fuel pool water, and condensate storage tank water are classified as treated water for aging management.

The Water Chemistry Control Program includes specifications for chemical species, impurities and additives, sampling and analysis frequencies, and corrective actions for control of reactor water chemistry. The Water Chemistry Program includes periodic monitoring and controlling of water chemistry to ensure System water chemistry is controlled to minimize contaminant concentration and mitigate loss of material due to general, crevice, and pitting corrosion and cracking caused by SCC. BFN Chemistry Control Program maintains a high water purity which reduces susceptibility to SCC. BFN uses hydrogen water and noble metal chemical application chemical additive programs.

The Water Chemistry Program establishes criteria where chemistry parameter data are recorded, evaluated, and trended in accordance with the EPRI water chemistry guidelines.

The Water Chemistry Program maintains maximum levels for various chemical parameters are maintained within the system specific administrative and action level limits as specified in the corresponding EPRI water chemistry guidelines.

Any evidence of aging effects or unacceptable water chemistry results are evaluated, the cause identified, and the condition corrected as specified in the BFN Water Chemistry Program. The BFN Water Chemistry Program contains specific actions required to be taken when measured water chemistry parameters are outside the specified range, corrective actions to take to bring the parameter back within the acceptable range (or to change the operational mode of the plant) within the time period specified in the EPRI water chemistry guidelines. Whenever corrective actions are taken to address an abnormal chemistry condition, the BFN Water Chemistry Program requires increased sampling or other appropriate actions to verify that the corrective actions were effective in returning the concentrations of contaminants, such as chlorides, fluorides, sulfates, and dissolved oxygen, to within the acceptable ranges.

The Water Chemistry program does not provide for detection of aging effects. However, components located in low flow or stagnant areas of plant systems will receive a one-time inspection prior to the subsequent period of extended operation. This inspection will be performed as part of the One-Time Inspection program (B.2.1.20).

NUREG-2191 Consistency

The Water Chemistry aging management program is consistent with the 10 elements of aging management program XI.M2, Water Chemistry, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Water Chemistry program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for Chemistry Control Program described in FSAR Section O.1.5 in support of preparing the BFN Subsequent License Renewal Application. The purpose of the program effectiveness review was to verify that the management of chemistry parameters is effectively managing plant water chemistry to minimize loss of material due to general, crevice, pitting corrosion, and crack initiation and propagation caused by stress corrosion cracking. The program effectiveness review was comprised of a review of testing results, Quality Assurance assessments, and any Condition Reports (CRs) entered into the Corrective Action Program during the period of extended operation. Chemistry control is monitored and maintained by a robust sampling and testing program. EPRI guidelines are used in the development and maintenance of the sampling and testing program. A review of Corrective Action Program documents entered during the period of extended operation related to chemistry control was conducted. The Chemistry Department routinely documents degraded parameters in the Corrective Action Program. This is driven by both department procedures and practices. The majority of the issues which document excursion of chemistry parameters are identified and documented at the exceedance of the threshold, or Good Practice, value. Actions to restore the parameter to within limits were documented, along with any needed follow-up testing, for the excursion of chemistry parameters. The review of the documented issues did not identify an adverse trend in performance.

   This operating experience provides objective evidence that the Chemistry Control Program is effectively being used to identify and correct off normal chemistry parameters. Maintenance of these parameters in allowable values minimizes loss of material due to general, crevice, pitting corrosion, and crack initiation and propagation caused by stress corrosion cracking. Continued implementation of the Chemistry Control Program will assure degraded conditions will be identified and corrected during the subsequent period of extended operation.

2. BFN Quality Assurance (QA) organization performed audits of the Chemistry Control Program. These are documented in QA audit reports in 2015, 2017, 2019, and 2021. In the 2021 audit, it was identified that the Chemistry Effectiveness was assessed as effective, with

no deficiencies. The 2019 audit determined that all requirements were met for sample location, system configuration, preconditioning, set points, and analysis completion. One administrative recommendation related to post activity document review was identified and documented in the Corrective Action Program. The corrective action created from this condition has been completed.

This operating experience provides objective evidence that evaluations are used in the Chemistry Control Program to assess program effectiveness and to identify deficient conditions in the program. This also provided objective evidence that the Corrective Action program is utilized to correct deficient conditions. This provides assurance that the Chemistry Control Program will be effective in protecting in-scope systems to ensure that intended functions are maintained during the subsequent period of extended operation.

3. BWRVIP-190, BWR Vessel and Internals Project: BWR Water Chemistry Guidelines, Revision 1, added a requirement to perform a hydrogen benchmark/ramp test to validate secondary parameters once every ten years, and after implementing a major operating change. This ramp test verifies the amount of hydrogen required to mitigate intergranular stress corrosion cracking in the regions of interest within the reactor. This change in the testing requirements resulting from BWRVIP-190, Revision 1, was documented in the Corrective Action Program in 2020. The benchmark tests were completed and documented in the Work Management Program.

   This operating experience provides objective evidence that industry initiatives are reviewed and evaluated for modifications to the BFN Chemistry Control Program. This provides assurance that industry operating experience driven changes to the program will protect the intended functions of in-scope systems during the subsequent period of extended operation.

4. During a review of the Corrective Action Program in 2022, it was identified that there are examples documented where chemistry sampling identified degrading trends in chemistry parameters. These Condition Reports document recommendations that were made to plant operators to take corrective action, such a demineralizer backwash and precoat. These actions were taken and resulted in the chemistry parameter returning to normal.

   This operating experience provides objective evidence that chemistry sampling procedure implementation, the Corrective Action Program, and coordination between Operations and Chemistry allow for early detection and remediation of degrading chemistry parameters. This provides assurance that the Chemistry Control Program will be effective in protecting in-scope systems to ensure that intended functions are maintained during the subsequent period of extended operation.

5. A Unit 3 reactor coolant chemistry sample obtained on July 28, 2020, was analyzed and indicated elevated conductivity. Trending was performed and identified that an indication of a chemical contamination started on July 1, 2020. Additional sampling and testing was performed and a tube leak in the main condenser was identified which allowed raw water to enter the condenser. As a result of the identification of the tube leak, the waterbox was removed from service. The specific tube was identified using helium gas, and the tube was plugged. The waterbox was returned to service with normal chemistry parameters. These conditions, and actions taken, were documented in the Corrective Action Program. Mitigating and corrective actions were developed to address this condition.

   This operating experience provides objective evidence that Chemistry Control Program evaluations are used to detect, identify and control deficient conditions in plant parameters, and for the Corrective Action program to correct those conditions. This provides assurance that chemistry parameters are maintained to protect in-scope systems to ensure that intended functions are maintained during the subsequent period of extended operation.

Conclusion

The Water Chemistry program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.3 Reactor Head Closure Stud Bolting

Program Description

The Reactor Head Closure Stud Bolting aging management program is an existing program that manages the aging effects of cracking due to stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC) and loss of material due to wear or corrosion for reactor vessel closure studs, washers, bushings, nuts, and threads in the flange. The program follows the examination requirements specified in the ASME Code, Section XI, Subsection IWB, Table IWB-2500-1, and preventive measures recommended within NRC Regulatory Guide 1.65 Revision 1, Materials and Inspection for Reactor Vessel Closure Studs, Revision 1.

The Reactor Head Closure Stud Bolting program implements ASME Code, Section XI inspection requirements through the Inservice Inspection (ISI) Program plan. The current ISI Program plan for the third 10-year inspection interval for BFN Unit 1, the fifth 10-year inspection interval for BFN Unit 2, and the fourth 10-year inspection interval for BFN Unit 3 (February 1, 2016 through January 31, 2026 for all) is based on the 2007 ASME Code, Section XI, including 2008 addenda.

The program uses visual, surface, and volumetric examinations in accordance with the general requirements of ASME Code, Section XI, Subsection IWA-2000 to monitor for cracking, loss of material, and coolant leakage. The extent and schedule for examining and testing the reactor head closure stud bolting components is as specified in Table IWB-2500-1 for B-G-1 components, “Pressure-Retaining Bolting Greater than 2 Inches in Diameter.” The studs and flange threads receive a volumetric examination, and the surfaces of nuts, washers, and bushings are inspected using VT-1 examination. The reactor vessel flange connection is within the ASME Code Class 1 pressure-retaining boundary that receives a visual VT-2 examination per Exam Category B-P during the system leakage test that is performed during each refueling outage.

The reactor head closure studs are fabricated from ASME SA-540 Grade B23 or B24 alloy steel. The installed studs, nuts, and washers on Units 1, 2, and 3 may have ultimate tensile strength greater than or equal to 170 kilo-pounds per square inch (ksi). The Reactor Head Closure Stud Bolting program includes other preventive measures described in Regulatory Guide 1.65, Revision 1, to prevent cracking. The reactor head closure studs, nuts, and washers were coated with an acceptable phosphate coating as a corrosion inhibitor that assists in retaining lubricants. In addition, a stable lubricant that does not contain molybdenum disulfide is applied to the studs, nuts, and washers prior to reactor vessel head re-installation.

Indications and relevant degraded conditions detected during the examinations performed are entered into the Corrective Action Program 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.

NUREG-2191 Consistency

The enhanced Reactor Head Closure Stud Bolting aging management program will be consistent with the 10 elements of aging management program XI.M3, Reactor Head Closure Stud Bolting, specified in NUREG-2191 with the following exception.

Exceptions to NUREG-2191

NUREG-2191 recommends, as a preventive measure that can reduce the potential for IGSCC or SSC, that the material used for existing closure studs should have an actual measured yield strength less than 150 ksi [1,034 megapascals (MPa)] for newly installed studs, or 170 ksi (1,172 MPa) ultimate tensile strength for existing studs. Certified Material Test Reports (CMTRs) for the materials used for the existing closure studs installed show that the studs may have ultimate tensile strength greater than or equal to 170 ksi. **Program Element Effected: Preventive Actions (Element 2)**

Justification for Exception

The reactor head closure studs and nuts are fabricated from SA-540 Grade B23 or B24 alloy steel. Both require a minimum yield strength of 130 ksi and a minimum ultimate tensile strength of 145 ksi. The reactor vessels are designed in accordance with the ASME Boiler and Pressure Vessel Code, Section III, 1965 Edition and applicable addenda requirements for Class A vessels. The materials used to fabricate all installed stud bolting components meet this design requirement.

The CMTR data for the installed studs and nuts includes sets of test results that include ultimate tensile strength values. Twelve of the 58 values given for ultimate tensile strength were equal to or exceeded 170 ksi. Since the CMTRs include some test results that indicate ultimate tensile strength greater than or equal to 170 ksi, it is concluded that these components may have ultimate tensile strength greater than or equal to 170 ksi. The average taken of the ultimate tensile strength test results for the studs and nuts is 164.7 ksi. The CMTR data indicates that the installed stud bolting components have ultimate tensile strength that is at most marginally greater than NUREG-2191 criteria for ultimate tensile strength.

All other preventive measures listed in NUREG-2191 AMP XI.M3, Reactor Head Closure Stud Bolting, that reduce the potential for cracking are met.

- Metal-plated stud bolting is not used, which could cause degradation due to corrosion or hydrogen embrittlement;
- A phosphate surface treatment was applied to the studs, nuts, and washers during fabrication to inhibit corrosion;
- An approved stable lubricant is applied to the studs, nuts, and washers whenever the reactor head is installed. The lubricant used does not contain molybdenum disulfide which has been shown to be a potential contributor to SCC.

The aging management review identified the stud bolting material as High Strength Low Alloy Steel Bolting with yield strength of 150 ksi or greater. This resulted in identifying cracking as an aging effect requiring management. The volumetric examination method required for stud inspection per ASME Code, Section XI, Table IWB-2500-1, Exam Category B-G-1 is appropriate to identify cracking. Ultrasonic testing results have been reviewed for each unit. No indications were identified by ISI program examinations of reactor head closure studs, indicating that the installed reactor head closure studs remain in good condition. Additionally, the Reactor Head

Closure Stud Bolting aging management program will continue to include volumetric examination per Table IWB-2500-1, Exam Category B-G-1, and therefore will be effective in managing cracking during the subsequent period of extended operation.

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Ensure the use of molybdenum disulfide (MoS_2) as a lubricant for reactor vessel closure studs is prohibited.

   Program Element Effected: Element 2: Preventive Actions

2. Revise implementing procedures to require that future replacement studs will not be metal plated, the studs will use a bolting material for closure studs that has an actual measured yield strength less than 150 kilo-pounds per square inch (ksi) [1,034 megapascals (MPa)], and the replacement studs will have a manganese phosphate or other acceptable surface treatment.

   Program Element Effected: Element 2: Preventive Actions

3. Ensure repair and replacement be performed in accordance with the requirements of IWA-4000 and the material and inspection guidance of Regulatory Guide 1.65, Revision 1. The maximum actual yield strength of replacement material will be limited to 150 ksi as recommended in Regulatory Guide 1.65, Revision 1.

   Program Element Effected: Element 7: Corrective Actions

Operating Experience

The following examples of operating experience provide objective evidence that the Reactor Head Closure Stud Bolting program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for the Reactor Head Closure Studs Program described in FSAR Section O.1.6 in support of preparing the BFN Subsequent License Renewal Application. The purpose of the program effectiveness review was to verify that the intent of the existing aging management program activities, to identify and correct, as warranted, age-related degradation of components monitored by the Inspections of the Reactor Head Closure Studs Program, are being effectively implemented in the initial license renewal period of extended operation. The program effectiveness review was comprised of a review of results of inspection implementation activities to date and pertinent issues in the Corrective Action Program, searching for identified age-related degradation of components related to the Reactor Head Closure Studs Program. The program manages the effects of aging on the BFN Unit 1, 2, and 3 Reactor Head Closure Studs that are within the scope of 10 CFR 54.4, Requirements for Renewal of Operating License for Nuclear Power Plants. The Reactor Head Closure Studs Program inspections are currently performed as part of the ASME Section XI Inservice Inspection (ISI) Program. Summaries of results of inspections conducted each refueling outage for each unit are maintained by the BFN Engineering Programs, BWRVIP Engineer. Review of the results covering the period of 2014 to 2022 contained in these summaries verify that required inspections have been conducted as required by Aging Management Program Implementing procedures. The review did not identify any significant age-related degradation of in-scope components.

   This operating experience provides objective evidence that the current ISI Program is being effectively implemented to manage aging effects of reactor head closure stud bolting components in accordance with ASME Section XI requirements, and that continued implementation of the Reactor Head Closure Stud Bolting aging management program will assure that the reactor head closure stud bolting components will continue to perform their intended functions during the subsequent period of extended operation.

2. During the Unit 1 refueling outage, U1R10, in 2014, reactor head closure studs and flange threads 1 through 92 were volumetrically examined using the ultrasonic test (UT) examination method. Reactor head closure nuts, washers 61 through 92 and bushings 68 through 71 were visually examined using the VT-1 method. There were no recordable indications.

   During the Unit 2 refueling outage, U2R19, in 2017, reactor head closure studs and flange threads 1 through 92 were volumetrically examined using the UT examination method. Reactor head closure nuts, washers 61 through 92, and bushings 22 through 25 were visually examined using the VT-1 method. There were no recordable indications.

   During the Unit 3 refueling outage, U3R18, in 2018, reactor head closure studs and flange threads 1 through 92 were volumetrically examined using the UT examination method. Reactor head closure bushings 22 through 25 were examined using the VT-1 method. There were no recordable indications. During the Unit 3 refueling outage, U3R19, in 2022, reactor head closure nuts and washers 31 through 60 were visually examined using the VT-1 method. There were no recordable indications.

   This operating experience relative to the Reactor Head Closure Stud Bolting program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking and loss of material. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. This operating experience demonstrates that the reactor head closure stud bolting components were inspected in accordance with ASME Code Section XI requirements using examination techniques that would identify cracking and loss of material during the fourth 10-year ISI interval. The reactor head closure stud bolting components were verified to be in excellent material condition.

3. During the period of extended operation, there have been two Quality Assurance Audit Reports and one self-assessment report that included a review of the Reactor Head Closure Studs Program. No deficiencies related to this program were identified.

   This example demonstrates that periodic self-assessments of the Reactor Head Closure Stud Bolting aging management program have been performed to identify and correct program elements that need improvement to maintain the quality performance of the program.

Conclusion

The enhanced Reactor Head Closure Stud Bolting program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.4 BWR Vessel ID Attachment Welds

Program Description

The BWR Vessel ID Attachment Welds aging management program is an existing condition monitoring program that manages cracking of reactor vessel internal attachment welds due to SCC, IGSCC, or cyclic loading in a reactor coolant environment. This program relies on augmented visual inservice examinations to detect cracking. The program substitutes the inspection and evaluation recommendations within BWRVIP-48 Revision 2, “BWR Vessel and Internals Project, Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines,” for the requirements within ASME Code, Section XI, Table IWB-2500-1, Examination Category B-N-2 via an NRC approved Request for Alternative to the requirements of the ASME Code. A similar Request for Alternative Implementation will need to be submitted to, and approved by the NRC, for the ISI inspection intervals that coincide with the subsequent period of extended operation.

The potential for cracking due to SCC and IGSCC is mitigated by maintaining high water purity as described in the Water Chemistry program (B.2.1.2), in addition to the implementation of a Hydrogen Water Chemistry program and an On-Line Noble Metal Chemistry program, both of which have been shown to be an effective method of mitigating SCC and IGSCC by reducing the Electrochemical Potential, which reduces the probability of crack growth and initiation in susceptible materials. The scope of the program includes the attachment welds for the steam dryer support and hold down brackets, guide rod brackets, feedwater sparger brackets, jet pump riser braces, core spray piping brackets, and surveillance sample holder brackets.

Any indications are evaluated in accordance with the guidance in BWRVIP-48 Revision 2. If flaws are found, the condition is entered into the Corrective Action Program and the scope of the inspection is expanded in accordance with the guidance provided in BWRVIP-48 Revision 2. The program uses the repair and replacement procedures in NRC staff-approved BWRVIP Guideline BWRVIP-52-A, “BWR Vessel and Internals Project Shroud Support and Vessel Bracket Repair Design Criteria.” The guidelines of BWRVIP-52-A provide general design guidance and acceptance criteria for permanent and temporary repair of the shroud support and vessel internal attachments.

NUREG-2191 Consistency

The BWR Vessel ID Attachment Welds aging management program is consistent with the 10 elements of aging management program XI.M4, BWR Vessel ID Attachment Welds, specified in NUREG-2191, with the following exception.

Exceptions to NUREG-2191

The BFN BWR Vessel ID Attachment Welds aging management program is based on the inspection, evaluation, and repair guidelines contained in BWRVIP-48 Revision 2, rather than BWRVIP-48-A as specified in NUREG-2191. **Program Elements Affected: Scope of Program (Element 1), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5)**

Justification for Exception

This exception is acceptable since, as discussed below, the changes to the BWRVIP-48-A NRC staff approved guidelines contained in BWRVIP-48 Revisions 1 and 2 do not involve establishing less conservative requirements and therefore did not require prior NRC review and approval according to the BWRVIP document screening process.

The inspection requirements for reactor vessel ID attachment welds contained in BWRVIP-48-A were originally based on the potential susceptibility of attachment welds to SCC given the existing state of knowledge. At the time that BWRVIP-48 was initially issued (1998), SCC of BWR internals was still largely in a discovery phase, with the frequency and ultimate extent of cracking largely unknown. As a result, the inspection program specified by BWRVIP-48 was purposely conservative. Over twenty years have elapsed since the initial issue of BWRVIP-48, and it was therefore reasonable for the BWRVIP to revisit the inspection requirements in BWRVIP-48 based on the current state of knowledge regarding performance in the field and understanding of the progression of SCC in BWRs. Hence, the subsequent issuance of BWRVIP-48 Revisions 1 and 2.

Per BWRVIP-94, Revision 4, “Program Implementation Guide,” when BWRVIP guidelines are approved by the Executive Committee and are initially distributed, or subsequently revised, each utility shall modify their vessel and internals program documentation to reflect the new requirements and shall implement the guidelines within two refueling outages, unless a different schedule is identified by the BWRVIP at the time of document distribution. If new guidelines approved by the Executive Committee includes revisions to NRC approved BWRVIP guidelines (as is the case with BWRVIP-48 Revisions 1 and 2, which revised the guidelines contained in BWRVIP-48-A), and the revised guidelines are less conservative than those approved by the NRC, these less conservative guidelines shall be implemented only after the NRC reviews and approves the changes. “NRC approved” generally means the document was submitted to the NRC for review and approval and a final Safety Evaluation Report (SER) has been issued and is incorporated into publication of a “-A” document or equivalent. Alternatively, if the revised guidelines are screened out from submittal to the NRC in accordance with NEI 03-08, “Guidelines for the Management of Materials Issues,” Appendix C, utilities may implement the revised guidelines subject to any licensing restrictions at the site (e.g., commitments to use previous revisions under license renewal or with ASME Code relief requests).

Both Revisions 1 and 2 of BWRVIP-48 received screening evaluations performed in accordance with Appendix C of NEI 03-08, Rev. 4, “Document Screening.” In both cases, the screening evaluation concluded that the BWRVIP-48 revision could be generically released for implementation by the United States BWRVIP members without prior NRC review and approval, based in part on detailed evaluation of operating experience, and the results of a qualitative risk assessment performed per Appendix C of NEI 03-08, Rev. 4 which considered SCC susceptibility, residual stress state, flow induced vibration potential and flaw tolerance. Additionally, the changes implemented in Revisions 1 and 2 of BWRVIP-48 were consistent with previous inspection optimization efforts that have been previously accepted by the NRC.

Therefore, the use of BWRVIP-48 Revision 2 rather than BWRVIP-48-A in the BFN BWR Vessel ID Attachment Welds aging management program is an acceptable exception to NUREG-2191 Elements 1, 3, 4, and 5.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the BWR Vessel ID Attachment Welds program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for the BWR Vessel ID Attachment Welds program described in FSAR Section O.1.7 in support of preparing the BFN Subsequent License Renewal Application. The purpose of the program effectiveness review was to verify that the existing aging management program activities, to identify and correct, as warranted, age-related degradation of components monitored by the Inspections of the BWR Vessel ID Attachment Welds program, are being effectively implemented in the initial license renewal

period of extended operation. The program effectiveness review was comprised of a review of inspection implementation activities to date and pertinent issues in the Corrective Action Program, searching for identified age-related degradation of components related to the BWR Vessel ID Attachment Welds program. The program manages the effects of aging on the BFN Units 1, 2, and 3 Reactor Vessel Inside Diameter Attachment Welds that are within the scope of license renewal. The BWR Vessel ID Attachment Welds program inspections are performed as part of the previously existing BWR Vessel Inservice Inspection Program. The BWR Vessel ID Attachment Welds program inspections are performed by the Inservice Inspection program. Summaries of results of inspections conducted each refueling outage for each unit are maintained by the BFN Engineering Programs, BWRVIP Engineer. Review of the results contained in these summaries verify that required inspections have been conducted as required. The review did not identify age-related degradation of in-scope components.

This operating experience provides objective evidence that the current Reactor Vessel and Internals ISI Program is being effectively implemented to manage aging effects in accordance with BWRVIP-48-Rev 2 guidance and that continued implementation of the BWR Vessel ID Attachment Welds aging management program will assure that the reactor vessel interior attachment welds will continue to perform their intended functions during the subsequent period of extended operation.

2. The Unit 1 reactor vessel interior attachment welds for the core spray piping brackets were inspected in 2014 using the Enhanced Visual Examination (EVT-1) method. No indications of cracking were identified. The attachment welds for the steam dryer support brackets were inspected in 2016 using the EVT-1 method. No indications of cracking were identified. The feedwater sparger brackets were inspected in 2016 using the EVT-1 method. No indications of cracking were identified. The attachment welds for the jet pump riser braces were inspected in 2016 and 2018 using the EVT-1 method. No indications of cracking were identified. The Unit 2 reactor vessel interior attachment welds for the steam dryer support brackets were inspected in 2013 using the EVT-1 method, No indications were identified. Attachment welds for the core spray piping brackets were inspected in 2015 using the EVT-1 method. No indications were identified. Attachment welds for the jet pump riser braces were inspected in 2019 using the EVT-1 method. No indications of cracking were identified. The Unit 3 reactor vessel interior attachment welds for the core spray piping brackets were inspected in 2014 and 2016 using the EVT-1 method. No indications were identified. Attachment welds for the jet pump riser braces were inspected in 2014 and 2018 using the EVT-1 method. No indications of cracking were identified.

   This operating experience provides objective evidence that the current Reactor Vessel and Internals ISI Program is being effectively implemented to manage aging effects in accordance with BWRVIP-48-Rev 2 guidance and that continued implementation of the BWR Vessel ID Attachment Welds aging management program will assure that the reactor vessel interior attachment welds will continue to perform their intended functions during the subsequent period of extended operation.

3. In 2015, a self-assessment was performed associated with the BWR Vessel Internals Inspection program during the period of extended operation, which included the BWR Vessel ID Attachment Welds program. This self-assessment identified one Area For Improvement associated with the BWR Vessel ID Attachment Welds program; some industry operating experiences potentially applicable to the Reactor Pressure Vessel Internals Inspection (RPVII) Program have not been entered into the tracking system for evaluation of applicability. This issue was addressed in the Corrective Action Program and resulted in actions for Engineering Programs to evaluate recent industry operating experience for applicability to the

BFN RPVII Program and to revise implementing procedures for this program, to include wording for the operating experience evaluation process to standardize the operating experience review process and prevent omissions in the future. These actions are complete. During the period of extended operation, there have been two Quality Assurance Audit Reports that included a review of the BWR Vessel ID Attachment Welds program. No deficiencies related to this program were identified.

This example demonstrates that periodic self-assessments of the BWR Vessel ID Attachment Welds aging management program have been performed to identify and correct program elements that need improvement to maintain the quality performance of the program.

Conclusion

The existing BWR Vessel ID Attachment Welds program provides reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.5 BWR Stress Corrosion Cracking

Program Description

The BWR Stress Corrosion Cracking aging management program is an existing condition monitoring and mitigative program that manages IGSCC in piping and piping welds made of stainless steel and nickel-based alloy that are 4 inches or larger in diameter in reactor coolant greater than 200 degrees F, regardless of Code classification. The program also applies to pump casings, valve bodies, and reactor vessel attachments. The program implements the program delineated in NUREG-0313, Revision 2, and NRC Generic Letter (GL) 88-01 and its Supplement 1. The program includes preventive measures to mitigate IGSCC, and inspection and flaw evaluation to monitor IGSCC and its effects.

Reactor coolant water chemistry is controlled and monitored in accordance with EPRI guidelines to maintain high water purity and reduce susceptibility to SCC or IGSCC as described in the Water Chemistry program (B.2.1.2). The Core Spray and Recirculation Inlet safe ends were replaced with IGSCC resistant material, and in the case of the Recirculation inlet safe ends an improved design was used which eliminated crevices. These changes in materials and design mitigate the possibility of future IGSCC. Hydrogen water chemistry and on-line noble metals chemical application have been implemented to further reduce susceptibility of the piping systems exposed to reactor coolant to SCC or IGSCC.

The program addresses the management of crack initiation and growth due to IGSCC in the piping, welds, and components through the implementation of the ISI program in accordance with ASME Code, Section XI. Inservice inspections, performed as augmented requirements of the Section XI ISI program, ensure that aging effects are identified and repaired before the loss of intended function of in-scope components. The inspection frequency for welds classified in accordance with NRC GL 88-01 as IGSCC Category B through G is per the recommendations provided in the staff-approved BWRVIP-75-A, “BWR Vessel and Internals Project Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules,” for normal water chemistry conditions.

Inspection and flaw evaluation is conducted in accordance with the ISI program plan. If a flaw exceeds the applicable acceptance standards, then the condition is entered into the Corrective

Action Program and an analytical evaluation is performed in accordance with IWB-3640 to determine its acceptability for continued service without repair or replacement. Evaluations are performed using the applicable crack growth rate provided by ASME Code, Section XI. BWRVIP-14-A, BWRVIP-59-A, BWRVIP-60-A, and BWRVIP-62 Revision 2 also provide approved guidelines that can be used for evaluating crack growth in stainless, nickel alloys, and low-alloy steels. In accordance with NRC GL 88-01, repair of an IGSCC flaw, or an evaluation performed to accept a flaw must be approved by the NRC before resuming power operation.

Corrective action is performed in accordance with the guidance for replacement, weld overlay repair, and stress improvement provided in industry documents, including NRC GL 88-01, NUREG-0313, Revision 2, ASME Code, Section XI, Subsection IWA-4000, and approved Code Cases.

NUREG-2191 Consistency

The enhanced BFN BWR Stress Corrosion Cracking aging management program will be consistent with the 10 elements of aging management program XI.M7, BWR Stress Corrosion Cracking, specified in NUREG-2191, with the following exception.

Exceptions to NUREG-2191

There is a difference in the BWRVIP-62 report revision recommended in the GALL-SLR and the revision currently being implemented at BFN. BFN currently uses BWRVIP-62 Revision 2 instead of BWRVIP-62-A specified in NUREG-2191. **Program Elements Affected: Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5)**

Justification for Exception

Per BWRVIP-94, Revision 4, “Program Implementation Guide,” when BWRVIP guidelines are approved by the Executive Committee and are initially distributed, or subsequently revised, each utility shall modify their vessel and internals program documentation to reflect the new requirements and shall implement the guidelines within two refueling outages, unless a different schedule is identified by the BWRVIP at the time of document distribution. If new guidelines approved by the Executive Committee includes revisions to NRC approved BWRVIP guidelines (as is the case with BWRVIP-62 Revision 2, which revised the guidelines contained in BWRVIP-62-A), and the revised guidelines are less conservative than those approved by the NRC, these less conservative guidelines shall be implemented only after the NRC reviews and approves the changes. “NRC approved” generally means the document was submitted to the NRC for review and approval and a final Safety Evaluation Report (SER) has been issued and is incorporated into publication of a “-A” document or equivalent. Alternatively, if the revised guidelines are screened out from submittal to the NRC in accordance with NEI 03-08, “Guidelines for the Management of Materials Issues,” Appendix C, utilities may implement the revised guidelines subject to any licensing restrictions at the site (e.g., commitments to use previous revisions under license renewal or with ASME Code relief requests).

In the case of BWRVIP-62, the latest revision (Revision 2) has not been reviewed and approved by the NRC. Revision 2 of BWRVIP-62 received a screening evaluation performed in accordance with Appendix C of NEI 03-08, Revision 4, “Document Screening.” The screening evaluation concluded that the BWRVIP-62 revision could be generically released for implementation by the United States BWRVIP members without prior NRC review and approval. Therefore, the use of

BWRVIP-62 Revision 2 rather than BWRVIP-62-A in the BFN BWR Stress Corrosion Cracking aging management program is an acceptable exception to NUREG-2191 Elements 4 and 5

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Revise implementing procedures to explicitly state that the approved guidelines contained in BWRVIP-14-A, BWRVIP-59-A, BWRVIP-60-A, and BWRVIP-62 Revision 2 are used for evaluating crack growth in stainless, nickel alloys, and low-alloy steels.

   Program Elements Affected: Element 5 - Monitoring and Trending, Element 7 - Corrective Actions

2. Revise implementing procedures to explicitly state that, in accordance with NRC GL 88-01, repair of an IGSCC flaw, or an evaluation performed to accept a flaw must be approved by the NRC before resuming power operation.

   Program Elements Affected: Element 5 - Monitoring and Trending, Element 7 - Corrective Actions

3. Revise implementing procedures to explicitly state that corrective actions for stress corrosion cracking are performed in accordance with the guidance for replacement, weld overlay repair, and stress improvement provided in industry documents, including NRC GL 88-01, NUREG-0313, Revision 2, ASME Code, Section XI, Subsection IWA-4000, and approved Code Cases.

   Program Elements Affected: Element 5 - Monitoring and Trending, Element 7 - Corrective Actions

Operating Experience

The following examples of operating experience provide objective evidence that the BWR Stress Corrosion Cracking program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for the BWR Stress Corrosion Cracking program described in FSAR Section O.1.10. The purpose of the program effectiveness review was to verify that the existing aging management program activities, to identify and correct, as warranted, age-related degradation of components monitored by the Inspections of the BWR Stress Corrosion Cracking program, are being effectively implemented in the initial license renewal period of extended operation. The program effectiveness review was comprised of a review of inspection implementation activities to date and pertinent issues in the Corrective Action Program, searching for identified age-related degradation of components related to the BWR Stress Corrosion Cracking program. The program manages the effects of aging on the BFN Units 1, 2, and 3 austenitic stainless steel piping four inch or larger in diameter containing reactor coolant at a temperature above 200 degrees Fahrenheit during power operation, that are within the scope of license renewal. The BWR Stress Corrosion Cracking program inspections are performed as part of the previously existing BWR Vessel Inservice Inspection Program. The BWR Stress Corrosion Cracking program inspections are performed by Inservice Inspection Program. Summaries of results of inspections conducted each refueling outage for each unit are maintained by the BFN Engineering Programs, Inservice Inspection Engineer. Review of the results contained in these summaries verify that required inspections have been conducted as required. The review identified that inspections of piping welds within the scope of the BWR Stress

Corrosion Cracking program are being performed as required (additional information is provided in Operating Experience Example 2 below).

This operating experience provides objective evidence that the current Inservice Inspection Program is being effectively implemented to manage aging effects in accordance with BWRVIP-75-A guidance and that continued implementation of the BWR Stress Corrosion Cracking aging management program will assure that the reactor vessel components susceptible to stress corrosion cracking will continue to perform their intended functions during the subsequent period of extended operation.

2. The Unit 1 NRC GL 88-01 Category D welds were inspected in 2014 by the Ultrasonic Testing (UT) method. No flaws were identified and no repairs were made. The Unit 2 NRC Generic Letter 88-01 Category C welds were inspected by the UT method in 2019. No flaws were identified and no repairs were made. Category D welds were inspected in 2013, 2015, 2017, and 2019 by the UT method. No flaws were identified and no repairs were made. The Unit 3 NRC GL 88-01 Category C welds were inspected in 2014 and 2018 by the UT method. No flaws were identified and no repairs were made.

   These examples demonstrate that the industry guidelines delineated in NRC GL 88-01, NUREG-0313, Revision 2, and BWRVIP-75-A continue to be effectively implemented to monitor the condition of welds within the scope of the BWR Stress Corrosion Cracking aging management program.

3. During the period of extended operation, there have been two Quality Assurance Audits and one Self-Assessment that included a review of the BWR Stress Corrosion Cracking program. No deficiencies related to this program were identified.

   This example demonstrates that periodic self-assessments of the BWR Stress Corrosion Cracking aging management program have been performed to identify and correct program elements that need improvement to maintain the quality performance of the program.

Conclusion

The enhanced BFN BWR Stress Corrosion Cracking program will provide reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.6 BWR Penetrations

Program Description

The BWR Penetrations aging management program is an existing condition monitoring program which is focused on managing the effects of cracking due to cyclic loading or stress corrosion cracking or intergranular stress corrosion cracking of the BWR instrumentation penetrations, CRD housing and ICMH penetrations, and the SLC/core plate differential pressure (ΔP) nozzle exposed to a reactor coolant environment. The program is implemented through station procedures that provide for mitigation of cracking through management of water chemistry and condition monitoring through examinations of reactor vessel penetration and nozzle welds. The examination categories include volumetric, surface, and visual examination methods.

The BWR Penetrations program augments the requirements of ASME Code, Section XI by incorporating the inspection and flaw evaluation recommendations of NRC staff approved BWRVIP guidelines BWRVIP-49-A, “Instrument Penetration Inspection and Flaw Evaluation

Guidelines," BWRVIP-27-A, "BWR Standby Liquid Control System/Core Plate ΔP Inspection and Flaw Evaluation Guidelines." The program uses the inspection and flaw evaluation guidance provided in BWRVIP-47-A, "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines," in lieu of the requirements of ASME Code, Section XI as a result of an NRC approved request for alternative implementation of the BWRVIP Program for Vessel Internals. The BWR Penetrations program also incorporates the water chemistry recommendations described in the Water Chemistry program (B.2.1.2).

The BFN Water Chemistry program maintains a high water purity which reduces susceptibility to SCC and IGSCC. The Water Chemistry program activities include periodic monitoring and controlling of water chemistry to ensure that known detrimental contaminants are maintained within pre-established administrative goals and action level limits.

In addition, BFN has established a Hydrogen Water Chemistry program and an On-Line Noble Metal Chemistry program, both of which have been shown to be an effective method of mitigating SCC and IGSCC by reducing the Electrochemical Potential, which reduces the probability of crack growth and initiation in susceptible materials.

The BWR Penetrations program performs repair and replacement activities in accordance with ASME Code Section XI, Article IWA-4000. The BFN BWR Penetrations program also uses the repair and replacement guidance in BWRVIP guidelines BWRVIP-53-A, BWRVIP-55-A, BWRVIP-57 Revision 1, and BWRVIP-58-A which are equivalent to, or exceed the applicable requirements of ASME Code, Section XI.

During each refueling outage, a visual inspection of the BWR instrumentation penetrations, CRD housing and ICMH penetrations, and SLC/core plate ΔP nozzle is performed during the reactor coolant pressure boundary system leakage test. Abnormal or unexpected findings are entered into the Corrective Action Program for evaluation and resolution.

NUREG-2191 Consistency

The enhanced BWR Penetrations aging management program will be consistent with the 10 elements of aging management program XI.M8, BWR Penetrations, specified in NUREG-2191, with one exception.

Exceptions to NUREG-2191

BWRVIP-57 Revision 1 is currently used as the BWRVIP guideline document for providing reactor pressure vessel instrument penetration repair design criteria rather than BWRVIP-57-A as recommended in the GALL-SLR. **Program Element Affected: Corrective Actions (Element 7)**

Justification for Exception

This exception is acceptable since, as discussed below, the changes to the NRC staff approved BWRVIP guidelines do not involve establishing less conservative requirements and therefore did not require prior NRC review and approval according to the BWRVIP document screening process.

Per BWRVIP-94, Revision 4, "Program Implementation Guide," when BWRVIP guidelines are approved by the Executive Committee and are initially distributed, or subsequently revised, each utility shall modify their vessel and internals program documentation to reflect the new requirements and shall implement the guidelines within two refueling outages, unless a different schedule is identified by the BWRVIP at the time of document distribution. If new guidelines approved by the Executive Committee includes revisions to NRC approved BWRVIP guidelines, and the revised guidelines are less conservative than those approved by the NRC, these less conservative guidelines shall be implemented only after the NRC reviews and approves the changes. “NRC approved” generally means the document was submitted to the NRC for review and approval and a final Safety Evaluation Report (SER) has been issued and is incorporated into publication of a “-A” document or equivalent. Alternatively, if the revised guidelines are screened out from submittal to the NRC in accordance with NEI 03-08 Appendix C, utilities may implement the revised guidelines subject to any licensing restrictions at the site (e.g., commitments to use previous revisions under license renewal or with ASME Code relief requests).

Section 1 and Appendix A of BWRVIP-57-A were revised in Revision 1 to add recent operational experience and descriptions of additional instrument penetration nozzle repairs that have been or could be implemented in the BWR fleet. The aging management requirements in BWRVIP-57, Revision 1 were screened using NEI-03-08, Revision 4, Appendix C, “Document Screening,” resulting in a determination that it could be generically released for implementation by U.S. BWRVIP members without prior U.S. NRC review and approval.

<u>Enhancements</u>

Prior to the subsequent period of extended operation, the following enhancement will be implemented in the following program element.

1. Revise implementing procedures to explicitly state that the approved guidelines contained in BWRVIP-53-A, BWRVIP-55-A, BWRVIP-57 Revision 1, and BWRVIP-58-A are used as a source of repair design criteria for reactor vessel internals components, as applicable.

   Program Element Affected: Element 7 - Corrective Actions

<u>Operating Experience</u>

The following examples of operating experience provide objective evidence that the BWR Penetrations program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for the BWR Penetrations program described in FSAR Section O.1.11. The purpose of the program effectiveness review was to verify that the existing aging management program activities, to identify and correct, as warranted, age-related degradation of components monitored by the Inspections of the BWR Penetrations program, are being effectively implemented in the initial license renewal period of extended operation. The program effectiveness review was comprised of a review of inspection implementation activities to date and pertinent issues in the Corrective Action Program, searching for identified age-related degradation of components related to the BWR Penetrations program. The program manages the effects of crack initiation and growth due to stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC) in instrument and standby liquid control (SLC) nozzle penetrations of the BFN Units 1, 2, and 3 reactor vessel penetrations. The BWR Penetrations program inspections are performed by Inservice Inspection Program. Summaries of results of inspections conducted each refueling outage for each unit are maintained by the BFN Engineering Programs, BWRVIP Engineer. Review of the results contained in these summaries verify that required inspections have been conducted (additional information is provided in Operating Experience Example 2 below). The

program effectiveness review also verified the recommendations of BWRVIP-27 and BWRVIP-49 are being implemented as documented in FSAR Section O.1.11.

This operating experience provides objective evidence that the current BWR Penetrations program is being effectively implemented to manage aging effects of reactor vessel penetrations, and that continued implementation of the BWR Penetrations aging management program will assure that the reactor vessel penetration components will continue to perform their intended functions during the subsequent period of extended operation.

2. The Unit 1 reactor vessel instrument penetrations N11A, N12A, N12B, N16A, and N16B were inspected in 2014, 2016, and 2018 by the UT method, and 2014, 2016, 2018, 2020, and 2022 by the VT method. No flaws were identified, and no repairs were made. The Unit 1 SLC penetration was inspected in 2014, 2016, 2018, 2019 and 2020, and 2022 by both the UT method and the VT method. No flaws were identified, and no repairs were made.

   The Unit 2 reactor vessel instrument penetrations N11A, N11B, N12B, N16A, and N16B were inspected in 2015, 2017, and 2019 by the UT method, and 2015, 2017, 2019, 2021, and 2023 by the VT method. No flaws were identified, and no repairs were made. The Unit 2 SLC penetration was inspected in 2015, 2017, 2019, and 2021, and 2023 by both the UT method and the VT method. No flaws were identified, and no repairs were made.

   The Unit 3 reactor vessel instrument penetrations N11A, N11B, N12A, N12B, N16A, and N16B were inspected in 2014, 2016, and 2018, by the UT method, and 2014, 2016, 2018, 2020, and 2022 by the VT method. No flaws were identified, and no repairs were made. The Unit 3 SLC penetration was inspected in 2014, and 2016, 2018, 2020, and 2022 by the VT method, and the SLC penetration was also inspected in 2018, 2020, and 2022 by the UT method. No flaws were identified, and no repairs were made.

   This operating experience demonstrates that the reactor vessel penetrations were inspected in accordance with industry guidelines delineated in BWRVIP-49 and BWRVIP-27 using examination techniques that would identify cracking and loss of material to assure that these components will be able to continue to perform their intended functions during the subsequent period of extended operation.

3. There has been one self-assessment associated with the BWR Vessel Internals Inspection program during the period of extended operation, which would include the BWR Penetrations program in July through August 2015. This self-assessment identified one Area For Improvement associated with the BWR Penetrations program; Some industry operating experiences potentially applicable to the RPVII program have not been entered into the tracking system for evaluation of applicability. This issue was addressed in the Corrective Action Program, which resulted in actions for Engineering Programs to evaluate recent industry operating experience for applicability to the BFN RPVII program and to revise aging management implementing procedures, to include wording for the operating experience evaluation process in an effort to standardize it and prevent omissions in the future. These actions have been completed.

   During the period of extended operation, there have been two Quality Assurance Audits (one conducted from August 25 to September 5, 2014, and one conducted from May 31 to June 10, 2016) that included a review of the BWR Penetrations program. No deficiencies related to this program were identified.

   This example demonstrates that periodic self-assessments of the BWR Penetrations aging management program have been performed to identify and correct program elements that need improvement to maintain the quality performance of the program.

Conclusion

The enhanced BWR Penetrations program will provide reasonable assurance that the aging effects are adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.7 BWR Vessel Internals

Program Description

The BWR Vessel Internals aging management program is an existing condition monitoring and mitigative program that includes inspections and flaw evaluations in conformance with the guidelines of applicable staff approved Boiling Water Reactor Vessel and Internals Project (BWRVIP) documents and provides reasonable assurance of the long-term integrity and safe operation of BWR vessel internal components that are fabricated of nickel alloy and stainless steel (including cast stainless steel and associated welds).

Available industry guidance includes time-dependent assumptions regarding component degradation mechanisms which have only been evaluated for 60 years of operation. To address this, NUREG-2192 includes three further evaluation items for an SLR applicant to address regarding BWR reactor vessel internals components aging mechanisms (Sections 3.1.2.2.12 through 3.1.2.2.14). In response, the BWRVIP developed BWRVIP-315 to disposition these further evaluations and identify any necessary plant-specific evaluations. For BFN, there are no additional components subject to degradation mechanisms for SLR. However, to implement the guidance in BWRVIP-315, some BWRVIP guidance documents require enhancement and revision (as shown in BWRVIP-315) in order to address operation beyond 60 years. These are documented in Appendix C of the BFN SLRA. The BFN BWR Vessel Internals aging management program recognizes the BWRVIP SLR guidance continues to develop and will continue to implement the most recent NRC-approved versions of the BWRVIP guidance. Note that there are BWRVIP comments to the draft NRC BWRVIP-315 safety evaluation which were submitted by letter dated January 20, 2022. The NRC has reviewed these comments and met with EPRI to discuss them, and a new version of the draft safety evaluation has subsequently been issued for BWRVIP review.

The BWR Vessel Internals aging management program manages the effects of cracking due to stress corrosion cracking (SCC), intergranular stress corrosion cracking (IGSCC), or irradiation assisted stress corrosion cracking (IASCC), cracking due to cyclic loading (including flow-induced vibration), loss of material, loss of fracture toughness due to neutron or thermal embrittlement, and loss of preload due to thermal or irradiation-enhanced stress relaxation. The program includes inspection and flaw evaluation in conformance with the guidelines of applicable BWRVIP reports and ASME Code, Section XI. The program mitigates these effects by managing water chemistry per the Water Chemistry program (B.2.1.2).

The program performs inspections for cracking and loss of material in accordance with the guidelines of applicable staff approved BWRVIP documents and the requirements of ASME Code, Section XI, Table IWB-2500-1. However, all three BFN units utilize an NRC Approved Request for Alternative Implementation of the BWRVIP Program for Vessel Internals in lieu of the requirements of ASME Code Section XI due to the fact that the NRC found that the TVA proposed alternative provided an acceptable level of quality and safety for the vessel internals components because the proposed alternate provides for equivalent or superior flaw detection and characterization with an examination frequency that is equivalent or more frequent than the ASME Code requirements. The Alternative Implementation of the BWRVIP Program for Vessel Internals includes examination methods, examination volume, frequency, training, successive and additional examinations, flaw evaluations, and reporting.

The impact of loss of fracture toughness on component integrity is indirectly managed by using visual or volumetric examination techniques to monitor for cracking in the components. This program also manages loss of preload for jet pump assembly hold-down beam bolts by performing visual inspections or stress analyses for adequate structural integrity. Manufacturer supplied guidance will be used for inspections of the replacement steam dryers.

The BWR Vessel Internals program specifies the necessary examinations to be performed during each outage based on the BWRVIP guidelines. BWRVIP-03 specifies VT-1 and EVT-1 examinations to detect surface discontinuities and imperfections such as cracks. Volumetric examinations are performed as specified by BWRVIP guidelines. VT-3 examinations are specified to determine the general condition of components by verifying parameters, such as clearances and displacements, and by detecting discontinuities and imperfections, such as loss of integrity of bolted or welded connections, or loose or missing parts, debris, corrosion, wear, or erosion. The examination procedures also identify the type and location of examination required for each component, as well as the basis for the examination.

Evaluations of reactor vessel internal components determined that supplemental inspections in addition to the existing BWRVIP examination guidelines are not necessary to manage loss of fracture toughness due to thermal aging embrittlement or neutron irradiation embrittlement and cracking due to IASCC during the subsequent period of extended operation. This determination is based on neutron fluence, cracking susceptibility, fracture toughness, and consequences of cracking or failure of the reactor vessel internal components.

The program allows for deviation from BWRVIP examination recommendations based on the requirements of NEI-03-08. Any relief request from the requirements of ASME Code, Section XI is submitted to the NRC for approval in accordance with 10 CFR 50.55a.

BWRVIP License Renewal Applicant Action Items listed in the NRC SERs for BWRVIP reports are addressed in BFN SLRA Appendix C.

The program utilizes the following BWRVIP guidelines for inspection, evaluation, and repair recommendations for the components listed. If a new or revised BWRVIP guideline approves a less conservative requirement than the staff approved version, the more restrictive requirement is followed until the staff approves the new or revised guideline.

Core Shroud: Inspections and flaw evaluations are performed in accordance with BWRVIP-76-A, Revision 1-A. The repair design criteria in BWRVIP-02-A, Revision 2, would be utilized in preparing a repair plan for the core shroud.

Core Plate: BWRVIP-25 Revision 1-A concludes that cracking due to fatigue is not an aging effect that requires management for the core plate. Repairs would be performed using the guidance from BWRVIP-50-A.

Core Spray: Inspections and evaluations are performed in accordance with BWRVIP-18-R2-A. The repair design criteria in BWRVIP-16-A and BWRVIP-19-A would be used in preparing a repair plan for Core Spray System components that are internal to the reactor vessel.

Shroud Support: Inspections and evaluations are performed in accordance with BWRVIP-38. The repair design criteria in BWRVIP-52-A would be utilized in preparing a repair plan for the core shroud support.

Jet Pump Assembly: Inspections and evaluations are performed in accordance with BWRVIP-41-R4-A and BWRVIP-138-R1-A. The repair design criteria in BWRVIP-51-A would be used in preparing a repair plan for jet pump components.

Low-pressure coolant injection (LPCI) Coupling: BFN Units 1, 2, and 3 reactor vessel internals do not include a LPCI coupling therefore inspections, flaw evaluations, and repairs performed in accordance with BWRVIP-42 Revision 1-A and BWRVIP-56-A do not apply.

Top Guide: Inspections and evaluations are performed in accordance with BWRVIP-26-A and BWRVIP-183. The repair design criteria in BWRVIP-50-A would be utilized in preparing a repair plan for the top guide. The program includes inspection of 10 percent of the grids beam cells containing control rod blades are inspected every 12 years, with at least five percent inspected within six years of the start of the BWRVIP-183 inspection cycle. This has been completed for the first 12-year period in all three BFN units. Inspections are performed using the enhanced visual inspection technique, EVT-1, method. The program also allows for inspections to be performed using UT once it becomes available. This inspection schedule will continue through the subsequent period of extended operation. Scope expansion if required will be performed to the requirements of BWRVIP-183-A.

Control Rod Drive (CRD) Housing and Lower Plenum Components: Inspections and evaluations are performed in accordance with BWRVIP-47-A. The inspections required by BWRVIP-47-A relative to CRD housings are further discussed in the BWR Penetrations program (B.2.1.6). The repair design criteria in BWRVIP-55-A and BWRVIP-58-A would be utilized in preparing a repair plan for the control rod drive housings.

Steam Dryer: Replacement Steam Dryers (RSD) designed and manufactured by GE-Hitachi Nuclear Energy with a design life of 40 years were installed in Unit 3 during Unit 3 Refueling Outage 18 (U3R18) in the Spring of 2018, in Unit 1 during Unit 1 Refueling Outage 12 (U1R12) in the Fall of 2018, and in Unit 2 during Unit 2 Refueling Outage 20 (U2R20) in the Spring of 2019 in preparation for Extended Power Uprate implementation during each unit's subsequent operating cycle. Since the subsequent period of extended operation for Unit 1 will end on December 20, 2053, Unit 2 on June 28, 2054, and Unit 3 on July 2, 2056, none of the RSDs will have exceeded their 40-year design lifetimes at the end of the subsequent period of extended operation.

While these RSDs maintain the same general configuration and function as the original steam dryers, there are considerable differences in design, material, and manufacturing details between the original steam dryers and the RSDs, primarily aimed at improving corrosion resistance and managing fatigue loads. The RSDs were built consistent with the design, materials requirements, and fabrication controls of BWRVIP-181-A and BWRVIP-84 Revision 2-A. The RSD materials were selected to be resistant to corrosion and stress corrosion cracking in the BWR steam/water environment in compliance with the guidance of BWRVIP-84 Revision 2-A and BWRVIP-181-A.

NUREG-2191 specifies in the scope description for AMP XI.M9, BWR Vessel Internals, that the guidance provided in BWRVIP-139-A will be used as the basis for aging management of BWR steam dryers during the subsequent period of extended operation. However, the scope and applicability of the BWRVIP-139, Revision 1-A report (which is the currently active, more recent NRC approved version of the BWRVIP document) only applies to the types of BWR steam dryer designs explicitly assessed in the BWRVIP-139, Revision 1-A report and do not apply to other steam dryer assemblies whose designs are outside the scope of those assessed in the report. BWRVIP-139, Revision 1-A assesses the original BFN steam dryers as described in Section 2.3.9 of the report. While the RSDs maintain the same general configuration and function as the original steam dryers, the considerable differences in design, materials, and manufacturing details render the BFN RSDs to be outside the scope of those dryers assessed in BWRVIP-139, Revision 1-A, and therefore it is not applicable to the RSDs.

GE-Hitachi provided recommendations for future inspections of the RSDs (GE-Hitachi Nuclear Energy Report No. 007N4785 - Revision 0, "Browns Ferry Nuclear Station (BFNS) - Recommendations for Future Inspections - Replacement Steam Dryer," November 2022), which was subsequently submitted to the NRC (Letter from TVA to NRC, "Long Term Steam Dryer Inspection Plan," dated January 20, 2023) pursuant to Unit 1 Operating License Condition 2.C(18)(i), Unit 2 Operating License Condition 2.C(18)(i), and Unit 3 Operating License Condition 2.C(14)(g) which required that a long term steam dryer inspection plan be submitted based on industry operating experience. Because the RSD design, and the materials and fabrication processes utilized, are expected to result in significantly improved resistance to stress corrosion cracking, the GE-Hitachi inspection recommendations focus primarily on the locations that may be susceptible to fatigue from flow-induced vibration. The locations identified are those indicated to have relatively significant cyclic loading during the dryer's operation, as determined by detailed stress analyses. The bases for these inspection recommendations from GE-Hitachi includes: (1) typical BWR practice, engineering judgement considering prior EPU experience, experience with original equipment steam dryers, and industry recommendations (BWRVIP-139-R1-A), (2) fatigue cracking experience with BWR steam dryers (GE Service Information Letter-644), (3) the additional weight of the RSD relative to the original equipment steam dryer, suggesting the need for additional attention to potential damage in the region of the steam dryer support lugs, and (4) removal locations of Flow Induced Vibration instrumentation and plug installations (Unit 3 RSD only).

The resolution standard for these visual examinations are "best effort VT-1" in accordance with BWRVIP-139-R1-A. Because there are not specific VT-3 resolution requirements per BWRVIP-139-R1-A, the resolution requirements of the recommended VT-3 examinations are the same as those for VT-1.

The BWR Vessel Internals aging management program will continue to perform periodic visual inspections of the RSDs to manage the aging effects of loss of material and cracking during the subsequent period of extended operation.

Guidelines for steam dryer repair design criteria provided in BWRVIP-181 Revision 2 will be used in preparing a repair plan for the RSDs.

Access Hole Covers: Inspections and evaluations are performed in accordance with BWRVIP-180 Revision 1. The commitment to enhance the BWR Vessel Internals aging management program to require visual inspection of the Access Hole Covers and inspection of the Access Hole Covers welds by UT examination (unless tooling constraints prohibit performance of a UT) was added to the scope of the BFN Initial License Renewal per the TVA response to NRC Request for Additional Information B.2.1.12-1(C) in TVA letter to the NRC dated January 31, 2005 and the TVA response to follow-up NRC Question (7) in TVA letter to the NRC dated May 25, 2005. This commitment was subsequently incorporated into the existing BWR Vessel Internals Aging Management Program and implemented for the Access Hole Covers by the BFN unit-specific procedures for the Reactor Pressure Vessel Internals Inspection

Program. The Reactor Pressure Vessel Internals Inspection Program incorporates the inspection requirements of BWRVIP-180 Revision 1 for the Access Hole Covers (VT-1 examination for the Unit 1, VT-3 and EVT-1 examinations for Unit 2 bolted permanent repair Access Hole Covers, and UT examination for the Unit 3 welded Access Hole Covers, which are scheduled to be replaced with the bolted design during Unit 3 Refueling Outage 21 (U3R21) in the Spring of 2024). Additionally, GEH provided additional recommendations for a one-time post-installation inspection and future inspections of the Access Hole Covers Permanent Repairs on Unit 2 (which are also now applicable to Unit 3 after installation of the bolted repair design) in GE Hitachi Nuclear Energy Report Number 006N8835 Revision 2, “Access Hole Cover Permanent Repair, Recommendations for Future Inspections,” which has been incorporated into the Unit 2 implementing procedure.

BWRVIP-217 provides guidelines for repair design criteria for welded Access Hole Covers and will be used in preparing a repair plan for the Unit 3 access hole covers, if needed, until they are permanently replaced with the bolted design. The BWRVIP-217 guidelines are not applicable to the permanent bolted repair Access Hole Covers.

<u>NUREG-2191 Consistency</u>

The BFN BWR Vessel Internals aging management program is consistent with the 10 elements of aging management program XI.M9, BWR Vessel Internals, specified in NUREG-2191, with the following exceptions.

<u>Exceptions to NUREG-2191</u>

1. Replacement Steam Dryer Inspections

   Inspection requirements in BWRVIP-139, Revision 1-A, “BWR Vessel and Internals Project Steam Dryer Inspection and Flaw Evaluation Guidelines,” will not be used for steam dryer inspections because BWRVIP-139, Revision 1-A does not explicitly address the GE-Hitachi Nuclear Energy designed and manufactured RSDs installed in BFN Units 1, 2, and 3. The original equipment General Electric steam dryers were replaced in Unit 3 during Unit 3 Refueling Outage 18 (U3R18)in the Spring of 2018, in Unit 1 during Unit 1 Refueling Outage 12 (U1R12) in the Fall of 2018, and in Unit 2 during Unit 2 Refueling Outage 20 (U2R20) in the Spring of 2019 in preparation for Extended Power Uprate implementation during each unit's subsequent operating cycle. **Program Elements Affected: Scope of Program (Element 1), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5), Acceptance Criteria (Element 6)**

   <u>Justification for Exception 1</u>

   BWRVIP-139, Revision 1-A does not explicitly address the GE-Hitachi Nuclear Energy designed and manufactured RSDs installed in BFN Units 1, 2, and 3. BWRVIP-139, Revision 1-A assesses the original BFN steam dryers as described in Section 2.3.9 of the report. While the RSDs maintain the same general configuration and function as the original steam dryers, the considerable differences in design, materials, and manufacturing details render the BFN RSDs to be outside the scope of those dryers assessed in BWRVIP-139, Revision 1-A, and therefore the inspection requirements contained in BWRVIP-139, Revision 1-A are not applicable as described in Limitation Number 1 of the NRC SER for BWRVIP-139, Revision 1-A, which states that the scope and applicability of the BWRVIP-139, Revision 1-A report only apply to the types of BWR steam dryer designs assessed in the BWRVIP-139, Revision 1-A report and do not apply to other steam dryer assemblies whose designs are outside the scope of those assessed in the report. The replacement steam dryers were designed to have a minimum service life of 40 years. Since the subsequent period of extended operation for Unit 1 will end on December 20, 2053, Unit 2 on June 28, 2054, and Unit 3 on July 2, 2056, the 40-year design service life will encompass the subsequent period of extended operation for each unit. GE-Hitachi provided recommendations for future inspections of the RSDs (GE-Hitachi Nuclear Energy Report No. 007N4785 - Revision 0, “Browns Ferry Nuclear Station (BFNS) - Recommendations for Future Inspections - Replacement Steam Dryer,” November 2022), which was subsequently submitted to the NRC (Letter from TVA to NRC, “Long Term Steam Dryer Inspection Plan,” dated January 20, 2023) pursuant to Unit 1 Operating License Condition 2.C(18)(i), Unit 2 Operating License Condition 2.C(18)(i), and Unit 3 Operating License Condition 2.C(14)(g) which required that a long term steam dryer inspection plan be submitted based on industry operating experience. The guidance provided in the Long Term Steam Dryer Inspection Plan, GEH Report 007N4785 Rev. 0, will provide the basis for managing age-related degradation of the RSDs in the BWR Vessel Internals program (B.2.1.7), in conjunction with the Water Chemistry program (B.2.1.2).

2. BWRVIP-03, BWRVIP-18, BWRVIP-25, BWRVIP-41, BWRVIP-62, BWR-76, BWRVIP-139, and BWRVIP-180 Revisions

   There are a few differences in the BWRVIP report revisions recommended in the GALL-SLR and those currently being implemented at BFN. These include BWRVIP-03 Rev. 20 versus BWRVIP-03 Rev. 1, BWRVIP-18 Rev. 2-A versus BWRVIP-18-A, BWRVIP-25 Rev. 1-A versus BWRVIP-25 Rev. 0, BWRVIP-41 Rev. 4-A versus BWRVIP-41 Rev. 0, BWRVIP-62 R2 versus BWRVIP-62-A, BWRVIP-76 Rev. 1-A versus BWRVIP-76-A, BWRVIP-139 Rev. 1-A versus BWRVIP-139-A, and BWRVIP-180 Rev. 1 versus BWRVIP-180 Rev. 0. **Program Element Affected: Scope of Program (Element 1)**

   <u>Justification for Exception 2</u>

   With respect to the inspection and examination guidance contained in the BWRVIP guidelines listed in this exception, there are no cases where the current guideline revision being implemented at BFN is not NRC-approved and is also less conservative from the standpoint of inspection scope and frequency than the revision cited in the SLR GALL. Either the guideline has received an NRC SER, or the guideline requirements are more restrictive than the version cited in the GALL-SLR. This exception is therefore acceptable since, as discussed below, the changes to the NRC staff approved BWRVIP guidelines do not involve establishing less conservative requirements and therefore did not require prior NRC review and approval according to the BWRVIP document screening process. The only BWRVIP guideline cited in the BFN BWR Vessel Internals program that has been subject to revisions over time without explicit NRC approval is BWRVIP-03. BWRVIP-03 provides standards for implementation of examinations as well as demonstration and documentation requirements. The BWRVIP revises BWRVIP-03 periodically to add new demonstrations. However, after approving BWRVIP-03 Revision 1 in 1999, NRC review of Revisions 2 and 3 resulted in the NRC staff concluding that, so long as the demonstration and documentation processes in BWRVIP-03 are not fundamentally changed, there was no need for the staff to issue Safety Evaluations on later revisions. Subsequent revisions to BWRVIP-03 continue to be provided to the NRC for information only. As such, implementation of later versions of BWRVIP-03 in no way represents use of less conservative criteria than those approved by NRC. Per BWRVIP-94, Revision 4, “Program Implementation Guide,” when BWRVIP guidelines are approved by the Executive Committee and are initially distributed, or subsequently revised, each utility shall modify their vessel and internals program documentation to reflect the new requirements and shall implement the guidelines within two refueling outages, unless a different schedule is identified by the BWRVIP at the time of document distribution. If new guidelines approved by the Executive Committee includes revisions to NRC approved BWRVIP guidelines, and the revised guidelines are less conservative than those approved by the NRC, these less conservative guidelines shall be implemented only after the NRC reviews and approves the changes. “NRC approved” generally means the document was submitted to the NRC for review and approval and a final Safety Evaluation Report (SER) has been issued and is incorporated into publication of a “-A” document or equivalent. Alternatively, if the revised guidelines are screened out from submittal to the NRC in accordance with NEI 03-08 Appendix C, utilities may implement the revised guidelines subject to any licensing restrictions at the site (e.g., commitments to use previous revisions under license renewal or with ASME Code relief requests). All of the revised BWRVIP guidelines in this exception received NRC approval with the exception of BWRVIP-03 Revision 20 (discussed above), BWRVIP-62 Revision 2, and BWRVIP-180 Revision 1. All three of these guidelines received screening evaluations performed in accordance with Appendix C of NEI 03-08, Rev. 4, “Document Screening.” In all cases, the screening evaluation concluded that the BWRVIP guideline revision could be generically released for implementation by the United States BWRVIP members without prior NRC review and approval.

3. Core Plate Hold-down Bolt Visual Inspections

The BFN BWR Vessel Internals aging management program will not manage the loss of preload due to thermal or irradiation-enhanced stress relaxation of the core plate hold-down bolts by performing visual inspections. **Program Element Affected: Parameters Monitored or Inspected (Element 3)**

Justification for Exception 3

On March 23, 2020, the BWRVIP received the final NRC SE for BWRVIP-25, Revision 1. BWRVIP Letter 2020-021 was subsequently distributed to the EPRI BWRVIP members on April 2, 2020, and served as notification that BWRVIP- 25, Revision 1 could be implemented subject to the requirements stated in the report, the final NRC SE, and plant-specific licensing requirements. The major difference in Revision 1 from Revision 0 is to provide a comprehensive evaluation providing justification for the elimination of periodic core plate hold-down bolt inspections, which is contained in Appendix I of the report. Upon issuance of the SE, TVA contracted with Structural Integrity Associates to prepare a Core Plate Bolt Evaluation in accordance with BWRVIP-25, Revision 1, and this evaluation provided justification for not examining the core plate bolts at BFN Units 1, 2, and 3 and closing the generic deviation disposition that existed at the time. BWRVIP-25, Revision 1-A was issued in September 2020, and incorporates all changes to BWRVIP-25, Revision 1 that were requested by the final NRC SE. Elimination of the requirement to perform core plate rim hold-down bolt inspections was subsequently incorporated into the existing BFN BWR Vessel Internals AMP Basis Document procedure and the applicable implementing procedures. For SLR, the plant-specific core support plate rim hold-down bolt loss of preload TLAA, performed consistent with BWRVIP-25 Revision 1-A, as well as the justification for elimination of the inspection of core plate rim hold-down bolts in accordance with BWRVIP-25 Revision 1-A Appendix I have been updated to account for the 80-year fluence projections to the end of the subsequent period of extended operation, and shows that the generic bolt stress analysis in BWRVIP-25 Revision 1-A remains bounding for the subsequent period of extended operation and that core plate rim hold-down bolt inspections are not required for the subsequent period of extended operation because of the IGSCC resistance of the bolts, excellent BWR industry field experience, and a margin assessment on the number of bolts required to meet allowable limits.

4. BWRVIP-100 Revision

   There is a difference in the BWRVIP report revision recommended in the GALL-SLR (BWRVIP-100-A) and the version currently implemented at BFN (BWRVIP-100, Revision 2). **Program Element Affected: Monitoring and Trending (Element 5)**

   <u>Justification for Exception 4</u>

   With respect to inspection and examination guidance, there are no cases where the current guideline revision being implemented is not NRC-approved and is also less conservative from the standpoint of inspection scope and frequency than the revision cited in the GALL-SLR. Either the guideline has received an NRC SER, or the guideline requirements are more restrictive than the version cited in the GALL-SLR.

   BWRVIP-100, Revision 2 is based on the following previously published reports:

   - BWRVIP-100-A: BWR Vessel and Internals Project, Updated Assessment of the Fracture Toughness of Irradiated Stainless Steel for BWR Core Shrouds. EPRI, Palo Alto, CA: 2006. 1013396.
   - BWRVIP-100, Revision 1: BWR Vessel and Internals Project, Updated Assessment of the Fracture Toughness of Irradiated Stainless Steel for BWR Core Shrouds. EPRI, Palo Alto, CA: 2010. 1021001.
   - BWRVIP-100, Revision 1-A: BWR Vessel and Internals Project, Updated Assessment of the Fracture Toughness of Irradiated Stainless Steel for BWR Core Shrouds. EPRI, Palo Alto, CA: 2016. 3002008388.

   Since the publication of BWRVIP-100, Revision 1-A, additional experimental data relating fracture toughness to neutron fluence have been published, most notably in BWRVIP-294, Revision 2. The motivation for conducting the testing that produced these data was based in part on the NRC Safety Evaluation for BWRVIP-100, Rev. 1 which recommended additional testing of irradiated stainless steels, particularly heat affected zone and weld metal, in a dose range applicable to BWRs. The experimental results obtained by EPRI as well as by other organizations have been used to reassess the relationship between fracture toughness and neutron fluence. BWRVIP-100 Revision 2 presents the results from that assessment.

5. BWRVIP-97 Revision

   BWRVIP-97 Revision 1 will be used as the applicable BWRVIP guideline document for performing weld repairs to irradiated vessel internals rather than BWRVIP-97-A as recommended in the GALL-SLR. **Program Element Affected: Corrective Actions (Element 7)**

   <u>Justification for Exception 5</u>

   As reactors age, it will become more important to consider irradiation effects on the weldability of stainless-steel components. The BWRVIP-97 Revision 1 guidelines provide a means for evaluating the weldability of reactor internal components. These guidelines incorporate a substantial number of irradiated materials test data from BWRVIP-151 that were not available at the time BWRVIP-97-A was developed. The revised guidance also includes a significant modification of the approach used to evaluate empirical weldability thresholds. Finally, this revision includes updated neutron transport calculations performed using the RAMA fluence methodology and considering service lives of up to 80 years.

   Per BWRVIP-94, Revision 4, “Program Implementation Guide,” when BWRVIP guidelines are approved by the Executive Committee and are initially distributed, or subsequently revised, each utility shall modify their vessel and internals program documentation to reflect the new requirements and shall implement the guidelines within two refueling outages, unless a different schedule is identified by the BWRVIP at the time of document distribution. If new guidelines approved by the Executive Committee includes revisions to NRC approved BWRVIP guidelines, and the revised guidelines are less conservative than those approved by the NRC, these less conservative guidelines shall be implemented only after the NRC reviews and approves the changes. “NRC approved” generally means the document was submitted to the NRC for review and approval and a final Safety Evaluation Report (SER) has been issued and is incorporated into publication of a “-A” document or equivalent. Alternatively, if the revised guidelines are screened out from submittal to the NRC in accordance with NEI 03-08 Appendix C, utilities may implement the revised guidelines subject to any licensing restrictions at the site (e.g., commitments to use previous revisions under license renewal or with ASME Code relief requests). The revised BWRVIP guideline in this exception received NRC approval of its previous version. The revised guideline received a screening evaluation performed in accordance with Appendix C of NEI 03-08, Rev. 4, “Document Screening.” The screening evaluation concluded that the BWRVIP guideline revision could be generically released for implementation by the United States BWRVIP members without prior NRC review and approval.

6. BWRVIP-84 Revision

BWRVIP-84 Revision 3 will be used rather than BWRVIP-84 Revision 2-A as the applicable BWRVIP guidance for maintaining the operating tensile stresses for core shroud repairs or other IGSCC repairs below a threshold limit that mitigates IGSCC of X-750 material. **Program Element Affected: Corrective Actions (Element 7)**

<u>Justification for Exception 6</u>

BWRVIP-84 did not initially allow the application of advanced material fabrication processes such as additive manufacturing or powder metallurgy/hot isostatic pressing. Such processes may offer attractive efficiencies and lead times in producing reactor internal components while providing equivalent or better properties than conventional processes such as forging, rolling, or casting. BWRVIP-84 did not prohibit advanced processes outright, but effectively excluded them by listing in the appendices the material specifications allowed to be used to fabricate reactor internal components. The specifications listed through Revision 2-A of BWRVIP-84 only include conventional wrought and cast products. In order to allow the use of materials fabricated by advanced processes, some form of qualification or demonstration is necessary as documented in a technical basis report. This revision of the guideline (BWRVIP-84, Revision 3) provides, in a new Section 4.5, a description of the required minimum content of a technical basis report along with the acceptance criteria for the various tests and examinations specified. Technical basis reports for advanced manufacturing processes, as required by Section 4.5, shall be submitted to EPRI prior to the use of such processes for the fabrication of replacement BWR internals components. A team of industry peers and subject matter experts will be assembled by EPRI to review the technical basis report. The review team will evaluate the extent to which the material in the technical basis report demonstrates that the manufacturing process meets the requirements and acceptance criteria set forth in Section 4.5. The findings of the peer review team will be documented in an EPRI BWRVIP letter. Processes for which the requirements of Section 4.5 have been met may be used in the fabrication of replacement BWR internals components upon issuance of the EPRI BWRVIP letter. Also, a new Section 1.6 has been added to describe the process for review and acceptance of technical basis reports. The allowance of advanced manufacturing processes also necessitated the addition of requirements for materials fabricated by metal powder processes to the individual appendices. Correction of some editorial items were also included in this revision. In accordance with NEI 03-08, “Guideline for the Management of Materials

Issues," the requirements in this report are considered "needed" when performing a repair to BWR internals. Although prior revisions of this report have been reviewed by the NRC, this report revision was evaluated using the NEI 03-08, Appendix C, "Document Screening" process. Using this process, it was determined that the report may be generically released for implementation without NRC approval and without a screening evaluation. This determination was based on Step 1a of the Applicability Evaluation and the report not meeting either of the conditions for defining aging management guidance.

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Revise implementing procedures to explicitly state that the approved guidelines contained in BWRVIP-14-A, BWRVIP-59-A, BWRVIP-60-A, and BWRVIP-62 R2 are used as a source of repair design criteria for reactor vessel internals components, as applicable.

   Program Element Affected: Element 1 - Scope of Program

2. Revise implementing procedures to implement BWRVIP-315-A and subsequent revisions approved by the NRC for BFN to use during the subsequent period of extended operation.

   Program Element Affected: Element 1 - Scope of Program

3. Revise implementing procedures to incorporate the requirement for justifying the frequency of subsequent inspection based on appropriate fracture toughness properties if component cracking is detected during inspection.

   Program Element Affected: Element 4 - Detection of Aging Effects

4. Revise implementing procedures to explicitly state that the approved guidelines contained in BWRVIP-14-A, BWRVIP-59-A, BWRVIP-60-A, BWRVIP-80-A and BWRVIP-99-A are used, as applicable, as a source of guidelines for evaluating crack growth in stainless steels, nickel alloys, and low-alloy steels, and that BWRVIP-100 R2 is used as a source for flaw evaluation methodologies and fracture toughness data for SS core shroud exposed to neutron irradiation.

   Program Element Affected: Element 5 - Monitoring and Trending

5. Revise implementing procedures to explicitly state that the guidelines contained in BWRVIP-97 Revision 1 are used as a source of guidelines for performing weld repairs to irradiated vessel internal components.

   Program Element Affected: Element 7 - Corrective Actions

6. Revise implementing procedures to explicitly state that the guidelines in BWRVIP-84, Revision 3 (or a later revision if approved and issued) are used to provide guidance on procurement, design and welding requirements, fabrication limitations, and numerous other issues (including maintaining operating tensile stresses below a threshold limit that mitigates IGSCC) for the four specific material types used for in-vessel repairs: 300 Series austenitic stainless steel, Alloy X-750, Type XM-19 and Alloy 718. The resulting specification is then used for designing repairs to the following internal components that fall within the scope of the BWRVIP program: core shroud, shroud support, core spray, top guide, core plate, standby liquid control line, jet pumps, control rod drive components, instrument penetrations, and vessel brackets.

   Program Element Affected: Element 7 - Corrective Actions

Operating Experience

The following examples of operating experience provide objective evidence that the BFN BWR Vessel Internals Aging Management Program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for the BFN BWR Vessel Internals Aging Management Program described in FSAR Section O.1.12. The purpose of the program effectiveness review was to verify that the existing aging management program activities, to identify and correct, as warranted, age-related degradation of components monitored by the Inspections of the BFN BWR Vessel Internals Aging Management Program, are being effectively implemented in the initial license renewal period of extended operation. The program effectiveness review was comprised of a review of inspection implementation activities to date and pertinent issues in the Corrective Action Program, searching for identified age-related degradation of components related to the BWRVIP. The program manages the effects of aging on the BFN Units 1, 2, and 3 Reactor Vessel Internals that are within the scope of 10 CFR 54.4, Requirements for Renewal of Operating License for Nuclear Power Plants. The BFN BWR Vessel Internals Aging Management Program inspections are performed by the Inservice Inspection Program. Summaries of results of inspections conducted each refueling outage for each unit are maintained by the BFN Engineering Programs, BWRVIP Engineer. Review of the results contained in these summaries verify that required inspections have been conducted. The review identified that inspections are being performed in accordance with BWRVIP guidelines. This review also revealed that indications of cracking or other aging effects have been identified during NDE (Non-Destructive Examinations) inspections, entered into the Corrective Action Program, and evaluated for continue use or repair in accordance with the appropriate BWRVIP guidelines. The performance of the NDE inspections, flaw evaluations, and proper re-inspection and scope expansion has resulted in the effective implementation of this aging management program. The program effectiveness review also verified the recommendations of the associated BWRVIP documents are being implemented as documented in FSAR Section O.1.12.

   This operating experience provides objective evidence that the current BFN BWR Vessel Internals Aging Management Program is being effectively implemented to manage aging effects and that continued implementation of the BFN BWR Vessel Internals Aging Management Program will assure that the aging effects of cracking, loss of material, loss of preload, and loss of fracture toughness in BWR reactor vessel internal components will be properly identified and managed and that the vessel internals components will continue to perform their intended functions during the subsequent period of extended operation.

2. During the BFN Unit 2 Refueling Outage 22 (U2R22) in the spring of 2023, In Vessel Visual Inspections were performed on the Top Guide Aligner Pin at 000° azimuth. While performing the inspection, a relevant indication was identified. The indication was located on top of the Aligner Pin Block toward the 359° side of the pin. The indication was measured by performing digital scaling against a reference object of known dimension in the examination area and was determined to be approximately 1.149 inches in length. As a result of the discovery, the U2R22 In Vessel Visual Inspections scope was expanded to include all 4 Aligner Pin locations in accordance with guidance provided in BWRVIP-26-A and no other relevant indications were noted. BFN Unit 2 is of the “BWR/3, 4 with Aligner Pin Plus Reinforcement Blocks” (Without Wedges) type configuration. BWRVIP-26-A directs the scope expansion required when an indication is reported, and also notes that only 35% of the weld need be intact for the hardware to perform its safety function. Analyses have shown that control rod insertion is not affected unless the extent of cracking is sufficient to result in a sustained movement of the top

guide by more than 2.5 inches, which is approximately comparable to a dynamic movement of 5 inches. The “egg crate” design of the top guide and the close packing of the fuel assemblies provides substantial redundancy to resist local movement. Therefore, potential movement would occur only if the entire core were repositioned. If multiple failures of the aligner pin assemblies were to occur, the top guide could shift position during a seismic event or other dynamic event. Such a position shift should be acceptable, unless the top guide had a final displacement in excess of 2.5 inches, which could impact the ability of control rods to insert. Since the three other Top Guide Alignment pins offer a redundant function and have been found in tact by expanded inspection scope, and the indication appears substantially smaller than the 65% flaw tolerance offered in BWRVIP-26-A for this configuration, the component appears to have substantial margin and redundancy to justify one cycle of operation (U2C23) until it will be reexamined and assessed in U2R23 (in the spring of 2025) for signs of growth or change.

This operating experience provides objective evidence that the current BFN BWR Vessel Internals Aging Management Program is being effectively implemented to manage aging effects and that continued implementation of the BFN BWR Vessel Internals Aging Management Program will assure that the aging effects of cracking, loss of material, loss of preload, and loss of fracture toughness in BWR reactor vessel internal components will be properly identified and managed and that the vessel internals components will continue to perform their intended functions during the subsequent period of extended operation.

3. Inspection of the Unit 1 core shroud was performed in 2016. Volumetric (Ultrasonic Test (UT)) examinations of the horizontal welds H-1 through H-7 and vertical welds V-3 and V-4 were performed. Indications were identified on all horizontal welds except H-5. No indications were identified on the vertical welds. The UT indications were entered into the Corrective Action Program. Evaluation of the indications determined that all welds should remain on the current 10-year re-inspection interval, as documented in implementing procedure. These core shroud welds will be inspected again in 2024, no additional action was required. In addition to the UT examinations, Enhanced Visual Test-1 (EVT-1) visual inspections for Off-Axis Cracking of welds H-4, V-4 and V-6 were conducted in accordance with BWRVIP Letter 2016-030. No indications were identified during the visual inspection of the core shroud.

   Inspection of the Unit 2 core shroud was performed in 2017. Volumetric UT examinations of the horizontal welds H-1 through H-7 and vertical welds V-7 and V-8 were performed. Indications were identified on all horizontal welds except H-4. No indications were identified on the vertical welds. The UT indications were entered into the Corrective Action Program. Evaluation of the indications determined that all welds should remain on the current 10-year re-inspection interval, as documented in the associated implementing procedure. These core shroud welds will be inspected again in 2027, no additional action was required. In addition to the UT examinations, EVT-1 visual inspections for Off-Axis Cracking of welds H-4, V-3 and V-6 were conducted in accordance with BWRVIP Letter 2016-030. No indications were identified during the visual inspection of the core shroud.

   Inspection of the Unit 3 core shroud was performed in 2018. Volumetric (UT) examinations of the horizontal welds H-1 through H-7 and vertical welds V-5 and V-6 were performed. Indications were identified on all horizontal welds except H-6 and V-5. The UT indications were entered into the Corrective Action Program. Evaluation of the indications determined that all welds should remain on the current 10-year re-inspection interval, as documented in the associated implementing procedure. These core shroud welds will be inspected again in 2028, no additional action was required. In addition to the UT examinations, EVT-1 visual inspections for Off-Axis Cracking of welds H-4, V-4 and V-6 were conducted in accordance with BWRVIP Letter 2016-030. No indications were identified during the visual inspection of the core shroud.

These examples demonstrate that core shroud inspections are being performed in accordance with BWRVIP guidelines and that the shrouds on all three units are being properly managed for aging. These examples also demonstrate that the Corrective Action Program is used effectively to identify and evaluate conditions adverse to quality.

4. During scheduled EVT-1 visual examinations of five Top Guide Grid Beam locations performed during BFN Unit 1 Refueling Outage 14 (U1R14) in the fall of 2022, a relevant indication was observed at the Northeast slotted notch of Cell Location 22-47 and entered into the Corrective Action Program for resolution. The indication traveled from the upper tip of the slotted notch diagonally upward and to the west along the grid beam for approximately 0.5". The indication had a horizontal component of 0.497" and a vertical component of 0.138". The most probable cause of the indication was postulated to be Irradiation Assisted Stress Corrosion Cracking (IASCC). In accordance with Section 8.2 of EPRI Document BWRVIP-183-A, “Top Guide Grid Beam Inspection and Flaw Evaluation Guidelines”, no scope expansion was required during U1R14 due to the identification of the indication since complete severance of the grid beam had not occurred. However, per Note 2 of Table 8-2 of BWRVIP-183-A, a plant-specific evaluation was performed for this flaw (documented in Structural Integrity Associates Report No. 2201214.301P, Revision 1, “Allowable Flaw Size Evaluation for the Top Guide Grid Beam Flaw Using a Solid Finite Element Model,” dated October 20, 2022) to determine a critical flaw size for the grid beam which was then used to determine if inspection scope expansion would be required during the following Unit 1 Refueling Outage 15 (U1R15) in the fall of 2024. The evaluation concluded that the indication emanating from the Northeast slotted notch of Cell location 22-47 was below 75% of the beam height and would remain so throughout the next operating cycle. Therefore, the flaw was determined to be acceptable without repair per BWRVIP-183-A, since the flaw was verified by plant specific evaluation to be less than a critical flaw size that would result in failure. However, follow up examination was added to the scope of future Unit 1 Refueling Outages 15 and 16 (U1R15, in the fall of 2024, and U1R16, in the fall of 2026) to evaluate the stability of the flaw as defined in Section 8.4 of BWRVIP-183-A with no further scope expansion required in future outages.

   This operating experience provides objective evidence that the current BFN BWR Vessel Internals Aging Management Program is being effectively implemented to manage aging effects and that continued implementation of the BFN BWR Vessel Internals Aging Management Program will assure that the aging effects of cracking, loss of material, loss of preload, and loss of fracture toughness in BWR reactor vessel internal components will be properly identified and managed and that the vessel internals components will continue to perform their intended functions during the subsequent period of extended operation

5. A review of the TVA Operating Experience Program evaluations of external OE relevant to the BFN BWR Vessel Internals Aging Management Program identified, a review of GE Service Information Letter 409, Rev 3, Incore Dry Tube Cracks, conducted in 2013. This review resulted in actions to revise the implementing procedures to conduct additional dry tube inspections. These inspections have been and continue to be conducted at the frequency recommended by the current version of GE Service Information Letter 409, Revision 5.

   This example demonstrates that the external operating experience program is used to improve the BFN BWR Vessel Internals Aging Management Program, assuring that these components will be able to continue to perform their intended functions during the subsequent period of extended operation.

Conclusion

The enhanced BFN BWR Vessel Internals program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.8 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)

Program Description

The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) aging management program is a new condition monitoring program that will provide assurance that RCPB CASS components (i.e., pump casings) with the potential for significant thermal aging embrittlement continue to meet their specified intended functions. The reactor coolant system components are inspected in accordance with the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section XI. This ASME Code required inspection is augmented to detect the effects of loss of fracture toughness due to thermal aging embrittlement of cast austenitic stainless steel (CASS) piping components except for valve bodies. This aging management program includes determination of the potential significance of thermal aging embrittlement of CASS components based on casting method, molybdenum content, and percent ferrite. For components for which thermal aging embrittlement is “potentially significant” as defined below, aging management is accomplished through either (a) qualified visual inspections, such as enhanced visual examination (EVT-1); or (b) a qualified ultrasonic testing (UT) methodology in accordance with ASME Code Section XI. Additional inspection or evaluations to demonstrate that the material has adequate fracture toughness are not required for components for which thermal aging embrittlement in is not significant. The scope of the program includes ASME Code Class 1 piping components constructed from CASS with service conditions above 250 °C (482 °F).

BFN does not have any Class 1 piping or fittings fabricated from CASS that are susceptible to thermal aging embrittlement of cast austenitic stainless steel. The main steam line flow restricting venturis are fabricated from CASS. The material of the venturis is low-molybdenum with a delta ferrite content of 18.3%. The venturis are exposed to a reactor steam environment that is significantly less than 320°C (610°F). Based on an evaluation of these material and environmental characteristics in accordance with the guidelines of EPRI Technical Report 1000976, “Evaluation of Thermal Aging Embrittlement for Cast Austenitic Stainless Steel Components - January 2001,” therefore these venturis are not within the Thermal Aging Embrittlement of CASS program. The Class 1 reactor recirculation pump casings are fabricated from CASS and are within the scope of the Thermal Aging Embrittlement of CASS aging management program.

The program will include a screening methodology to determine components for which thermal aging embrittlement is potentially significant based on casting method, molybdenum content, and percent ferrite. Ferrite content is calculated by using the Hull's equivalent factors (described in NUREG/CR-4513, Revision 1). Components with the potential for significant thermal aging embrittlement will be managed through either, qualified visual inspections, such as enhanced visual examination, or qualified ultrasonic testing methodology in accordance with ASME Code, Section XI.

Inspections or evaluations are not required for components for which thermal aging embrittlement is not significant. Reactor vessel internal (RVI) components fabricated from CASS are not within the scope of this aging management program. The BWR Vessel Internals program (B.2.1.7) contains aging management guidance for CASS RVI components of boiling water reactors (BWRs).

The program will provide for either enhanced visual inspections, or qualified ultrasonic testing methodology of susceptible components; it will not provide guidance on methods to mitigate thermal aging embrittlement. The program will not directly monitor for loss of fracture toughness that is induced by thermal aging; instead, the impact of loss of fracture toughness on component integrity will be indirectly managed by using visual or volumetric examination techniques to monitor for cracking in the components.

For piping components for which thermal aging embrittlement is “potentially significant,” the aging management program provides for qualified inspections of the base metal with the scope of the inspection covering the portions determined to be limiting from the standpoint of applied stress, operating time, and environmental considerations. Examination methods that meet the criteria of the ASME Code, Section XI, Appendix VIII are acceptable. For CASS piping, UT may be performed in accordance with the methodology of Code Case N-824, as conditioned by 10 CFR 50.55a.

The new BFN program will require inspection schedules in accordance with ASME Code, 2007 Edition through 2008 Addenda as modified by 10 CFR 50.55a, Section XI, IWB-2400 or IWC-2400, reliable examination methods, and qualified inspection personnel provide timely and reliable detection of cracks. If flaws are detected, the period of acceptability is determined from analysis of the flaw, depending on the crack growth rate and mechanism.

Flaws detected in reactor coolant pressure boundary ASME Code Class 1 CASS components are entered into the Corrective Action Program and evaluated in accordance with the applicable procedures of ASME Code, Section XI.

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

NUREG-2191 Consistency

The new Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) aging management program will be consistent with the 10 elements of aging management program XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS), specified in NUREG-2191

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following example of operating experience provide objective evidence that the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. BFN installed the fourth generation design of rotating assembly and seal cartridge for both recirculation pumps on Unit 1 prior to the 2007 restart. A visual examination of the pump interior was conducted on both pumps in July 2005 with no recordable conditions identified. Although not related to management of thermal embrittlement of cast austenitic stainless steel, this example provides objective evidence that the ASME Section XI Inservice Inspection program is effectively utilized to perform required opportunistic examinations on the reactor recirculation pump casings that are within the scope of the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program.

   The operating experience relative to the Thermal Aging Embrittlement of CASS aging management program did not identify an adverse trend in performance. The new Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program will effectively monitor and detect the aging effects of thermal aging embrittlement of CASS during the subsequent period of extended operation.

<u>Conclusion</u>

The new Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.9 Flow-Accelerated Corrosion

<u>Program Description</u>

The Flow-Accelerated Corrosion aging management program is an existing condition monitoring program that manages wall thinning caused by flow-accelerated corrosion (FAC) in steel piping and piping components exposed to reactor coolant, steam, and treated water environments. The program is based on commitments made in response to NRC Generic Letter 89-08, “Erosion/Corrosion Induced Pipe Wall Thinning,” and relies on implementation of the Electric Power Research Institute (EPRI) guidelines in NSAC-202L for an effective FAC program.

CHECWORKS^{TM} is used to predict component wear rates and remaining servicelife in the systems susceptible to FAC which provides reasonable assurance that structural integrity will be maintained between inspections. The model is revised if any changes in operating conditions or other factors that affect FAC (e.g., plant chemistry, power uprate) have occurred since the CHECWORKS^{TM} model was last updated. Changes may also result from plant modifications that effect FAC behavior such as material changes, the addition of piping systems, piping system configuration changes, and the addition or replacement of in-line components. The CHECWORKS^{TM} model is also refined by importing actual volumetric inspection data thickness measurements and re-running the wear rate analysis. This improves the predictive capability of the model to ensure that intended functions are maintained.Additionally, the program utilizes industry operating experience, plant experience, and engineering judgment of plant engineers to determine inspection locations.

The program also manages wall thinning caused by erosion in metallic heat exchanger components, piping and piping components exposed to reactor coolant, raw water, steam, and treated water in situations where periodic monitoring is used in lieu of eliminating the cause of various erosion mechanisms.

The program includes: (a) identifying all susceptible piping systems and components; (b) developing FAC predictive models to reflect component geometries, materials, and operating parameters; (c) performing analysis of FAC models and, with consideration of operating experience, selecting a sample of components for inspections; (d) inspecting components; (e) evaluating and trending 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.

FAC inspections and inspections performed for wall thinning caused by mechanisms other than FAC that do not meet acceptance criteria are evaluated in accordance with the Corrective Action Program.

<u>NUREG-2191 Consistency</u>

The enhanced Flow-Accelerated Corrosion aging management program will be consistent with the 10 elements of aging management program XI.M17, Flow Accelerated Corrosion, specified in NUREG-2191.

<u>Exceptions to NUREG-2191</u>

None.

<u>Enhancements</u>

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Ensure the management of wall thinning in screened-in components within the scope of SLR that are subject to erosion mechanisms in situations where periodic monitoring is used in lieu of elimination of the cause of various erosion mechanisms.

   Program Element Affected: Element 1 - Scope of Program

2. Ensure opportunistic visual inspections of up-stream and down-stream piping and components are performed during periodic pump and valve maintenance or during pipe replacements to assess internal surface conditions.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

3. Reassess piping systems that have been excluded from wall thickness monitoring due to operation less than 2 percent of plant operating time (as allowed by NSAC-202L) to ensure the exclusion remains valid and applicable for operation beyond 60 years. If actual wall thickness information is not available for use in this reassessment, a representative sampling approach can be used.

   Program Element Affected: Element 4 - Detection of Aging Effects

4. For erosion mechanisms, ensure the identification of susceptible locations is based on the extent-of-condition reviews from corrective actions in response to plant-specific and industry OE. A combination of operating experience, results of prior inspections, engineering judgment and analysis will be used to select inspection locations.

   Program Element Affected: Element 4 - Detection of Aging Effects

5. For erosion mechanisms, ensure:
   - Trending of wall thickness measurements to adjust the monitoring frequency and to predict the remaining service life of the component for scheduling repairs or replacements is required;
   - Inspection results are evaluated to determine if assumptions in the extent-of-condition review remain valid;
   - If degradation is associated with infrequent operational alignments, such as surveillances or pump starts/stops, then trending activities consider the number or duration of these occurrences; and
   - Periodic wall thickness measurements of replacement components may be required and should continue until the effectiveness of corrective actions has been confirmed.

   Program Element Affected: Element 5 - Monitoring and Trending
6. For erosion mechanisms, ensure the effectiveness of long-term corrective actions is verified when long term corrective actions include elimination of the cause by adjusting operating parameters and/or changing components' geometric designs. Ensure periodic monitoring activities continue for any component replaced, due to erosion, with an alternate material, since a material that is completely resistant to erosion mechanisms is not available.

   Program Element Affected: Element 7 - Corrective Actions

Operating Experience

The following examples of operating experience provide objective evidence that the Flow-Accelerated Corrosion program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for the Flow Accelerated Corrosion (FAC) Program described in FSAR Section O.1.14 in support of preparing the BFN Subsequent License Renewal Application. The purpose of the program effectiveness review was to verify that the intent of the existing aging management program activities, to identify and correct, as warranted, age-related degradation of components monitored by the FAC program, is being effectively implemented in the initial license renewal period of extended operation. The program effectiveness review was comprised of a review of inspection implementation activities to date and pertinent issues in the Corrective Action Program, searching for identified age-related degradation of components related to FAC. Pre-period of extended operation, visual inspection results, and resulting issues in the Corrective Action Program were reviewed. The reviews did not identify significant age-related degradation of equipment from a lack of FAC Program activities that would preclude it from performing its intended function. Attributes of the program that were reviewed included the selection of components to be inspected, the inspection of components, the evaluation of inspection data, sample expansion criteria, repair/replacement criteria, and program document updates. The performance of these activities was determined to comply with the requirements of the program. The Outage Summary reports since 2010 for each of the three units were reviewed. These reports have included Total Inspection Scope, Inspection Evaluations and Inspection Exemptions. All inspection evaluations were performed and checked by qualified personnel. All structural evaluations were performed if required. Repairs and replacements were performed in accordance with the corrective action and work order processes. The CHECWORKS™ program is used as a predictor of areas were FAC could be an issue and those areas are inspected. Other areas are inspected as well, and repairs / evaluations /

rescheduling of inspections are done in an attempt to reduce the possibility of through wall piping leaks.

These examples provide objective evidence of aging management program effectiveness during the first period of extended operation and provides objective evidence that the continued implementation of the program will effectively manage aging by identifying degradation prior to failure or loss of intended function during the subsequent period of extended operation.

2. During the spring 2022 refueling for Unit 3, one of the 8-inch 3C5 low pressure heater drain line elbows, was discovered to have several holes in the elbow. Based on that discovery, five additional inspections were added to the U3R20 outage FAC inspection list. Those inspections identified two additional drain lines in the 3C5 low pressure heater, with holes in them. Repair work was completed in the 3C5 low pressure heater to replace the original elbow with the holes in it, as well as repair with patches two other drain lines from the additional inspections.

   This example provides objective evidence that when issues are found during FAC inspections, applicable scope expansions are conducted to locate possible indications for repair. This will also effectively manage aging by identifying degradation prior loss of intended function during the subsequent period of extended operation.

3. During the Fall 2022 refueling outage for Unit 1, the number 3 feedwater heater shells were inspected for FAC. The 1B3 and 1C3 feedwater heater shells failed the FAC examinations. There were three areas on 1B3 shell and two areas on the 1C3 heater shell that were below limits. The acceptable thickness is 0.320 inches and the thickness in the areas of concern were at 0.202 inches on the 1B3 heater shell and 0.218 inches on the 1C3 heater shell. The repairs consisted of weld overlays with 1/4 inch weld material to restore shell thickness. The required repairs were completed.

   This example provides objective evidence that age-related inspection findings are entered into the Corrective Action Program and appropriate corrective actions are taken to evaluate and correct deficiencies. These actions will effectively manage aging by correcting degradation prior to loss of intended function during the subsequent period of extended operation.

4. NRC Information Notice 2019-08, Flow-Accelerated Corrosion Events, was issued to inform addressees of recent operating experience in which FAC events resulted in reactor trips. The BFN FAC Program was evaluated, and the following program features to address the issues identified in NRC Information Notice 2019-08 were verified. TVA uses corporate level procedures to standardize the implementation of the FAC program across the fleet. These procedures require that the FAC program maintains a set of drawings of all replacements within the scope of the FAC program. This set of drawings along with the inspection scoping program document ensure that historical replacements inform the program going forward. The procedure also provides guidance for scope expansions. All emergent replacements are also documented within the FAC Operating Experience Database. This database is reviewed for additional inspection locations periodically. The BFN FAC Program model has been reviewed by a third-party vendor. In addition, the BFN FAC model is reviewed after each outage by the FAC Program Manager. For inspections downstream of orifices, TVA procedures identify these as high wear locations and are prioritized for inspection before others in the same line.

   This example provides objective evidence that industry operating experience such as NRC Information Notices are entered into the Corrective Action Program and evaluated and used to improve the FAC program as necessary. These actions will support managing aging by ensuring program activities are sufficient to preclude component degradation prior loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Flow-Accelerated Corrosion program will provide reasonable assurance that the wall thinning aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.10 Bolting Integrity

Program Description

The Bolting Integrity aging management program is an existing condition monitoring program that manages aging of closure bolting for pressure-retaining components. The program includes periodic visual inspection of safety-related and nonsafety-related closure bolting for indications of loss of preload, cracking, and loss of material due to general, pitting, and crevice corrosion, microbiologically influenced corrosion (MIC), and wear as evidenced by leakage. The program utilizes recommendations and guidelines delineated in NUREG-1339 (dated June 1990), EPRI NP-5769 (dated April 1988), EPRI TR-1015336 (dated December 2007) and EPRI TR-1015337 (dated December 2007) for material selection (including minimizing the use of high strength bolting), use of approved lubricants (prohibiting the use of lubricants containing molybdenum disulfide), proper torquing, and leakage evaluations which are implemented during plant surveillance and maintenance activities.

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 Section XI. In addition, the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B.2.1.1) includes inspection of safety-related closure bolting on pressure-retaining components, and supplements this program. 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 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; 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. The evaluation includes, when practical, projections of identified corrosion or degradation rates until the next scheduled inspection or replacement. Inspections are performed by personnel qualified in accordance with station 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 station procedures that will include inspection parameters for items such as lighting, distance, and offset, which provide an adequate examination.

The program performs periodic sample inspections for closure bolting greater than 2 inches in diameter with actual yield strength greater than or equal to 150 ksi (1,034 MPa) and closure bolting for which yield strength is unknown. Volumetric examination will be performed in accordance with ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1.

The program also performs periodic sample inspections on submerged pressure-retaining bolting and closure bolting on pressure-retaining components that contain air or gas for which leakage is difficult to detect.

The periodic sampling inspections includes a representative sample of 20 percent of the population of bolt heads and threads (defined as bolts with the same material and environment combination) or a maximum of 25 bolts per population at each unit per 10-year interval during the subsequent period of extended operation. Opportunistic inspections during maintenance activities may be credited during the same 10-year period.

For sampling-based inspections, for a situation in which an acceptance criterion for allowable degradation is exceeded, and the aging effect causing the degradation for the material/environment combination 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 required to be performed. The number of additional inspections will be determined in accordance with the Corrective Action Program; however no fewer than five additional (or 20%, whichever is less) inspections will be performed of different components having the same material/environment/aging effect combination as the component(s) that did not meet the acceptance criterion. If these subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be performed to determine the further extent of inspections. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections for all BFN units' components having the same material, environment, and aging effect combination. The additional inspections will be completed within the same interval for which the original sample-based inspections are conducted. 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.

The following bolting is not managed by in the Bolting Integrity aging management program.

- The bolting components for the reactor vessel closure head are managed by the Reactor Head Closure Stud Bolting program (B.2.1.3).
- The Primary Containment (MC) pressure-retaining bolting is managed as part of the ASME Section XI, Subsection IWE program (B.2.1.29).
- Pressure-retaining bolting in a buried environment or underground with restricted access are inspected in conjunction with buried piping and component inspections performed as part of the Buried and Underground Piping and Tanks program (B.2.1.27).
- ASME Class 1, 2, 3, and MC piping and components support bolting, including NSSS component supports, is managed as part of the ASME Section XI, Subsection IWF program (B.2.1.30).
- Heating and ventilation system bolted joints are managed by the External Surfaces Monitoring of Mechanical Components program (B.2.1.23).
- Structural bolting, other than ASME Class 1, 2, 3, and MC piping and component supports bolting is managed as part of the Structures Monitoring program (B.2.1.33), and the Inspection of Water-Control Structures Associated with Nuclear Power Plants program (B.2.1.34).

- Crane and hoist bolting is managed by the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling System program (B.2.1.13).

NUREG-2191 Consistency

The enhanced Bolting Integrity aging management program will be consistent with the 10 elements of aging management program XI.M18, Bolting Integrity, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Ensure the maximum yield strength of replacement or newly procured pressure-retaining bolting material is limited to an actual yield strength less than 150 ksi (1,034 MPa) to preclude or minimize loss of preload and cracking.

   Program Element Affected: Element 2 - Preventative Actions

2. Revise implementing procedures to require periodic inspections of ASME Code Class 1, 2, and 3, and non-ASME Code class bolted joints for signs of leakage at least once per refueling cycle.

   Program Element Affected: Element 4 - Detection of Aging Effects

3. Revise implementing procedures to require sampling-based inspections to include a representative sample of 20 percent of the population of bolt heads and threads (defined as bolts with the same material and environment combination) or a maximum of 25 bolts per population at each unit per 10-year interval during the subsequent period of extended operation. Opportunistic inspections during maintenance activities may be credited during the same 10-year interval.

   Program Element Affected: Element 4 - Detection of Aging Effects

4. Revise implementing procedure(s) to require, for all closure bolting greater than 2 inches in diameter (regardless of code classification) with actual yield strength greater than or equal to 150 ksi and closure bolting for which yield strength is unknown, performance of volumetric examination in accordance with ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1 (i.e., acceptance standards, extent, and frequency of examination).

   Program Element Affected: Element 3 - Parameters Monitored or Inspected, and Element 4 - Detection of Aging Effects

5. Revise implementing procedures to establish the alternative methods of inspections of closure bolting in locations that preclude detection of joint leakage, as follows:

   - For systems containing air/gas, alternative inspections will include one or more of the following: (a) inspection consistent with that of submerged bolting; (b) visual inspection for discoloration when leakage from inside the piping system would discolor the external surfaces of the component; (c) monitoring and trending of pressure decay when the bolted connection is located within an isolated boundary; (d) soap bubble testing on the external mating surface of the bolted component; or (e) thermography, when the temperature of the process fluid is higher than ambient conditions around the component.

- Alternative inspection of carbon steel submerged closure bolting on the RHRSW, HPFP and CCW pumps located at the Intake Channel will consist of visual inspections by divers and periodic vibration monitoring (measurement). Divers will inspect for degraded, visibly loose, missing, or broken bolts. Periodic (minimum semiannual) vibration monitoring of the pump/motor assembly will also be performed as an alternative inspection method. Increased vibration could be an indication of degradation of the pump casing upper flange bolted joint. Vibration readings will be trended.
- For systems not normally pressurized, inspections for indication of leakage will be coordinated with scheduled operation of the system such as periodic surveillances. If system pressurization does not present the opportunity to perform the minimum required bolting inspections, then the visual inspections will be supplemented with torque checks to the extent that the bolting is not loose.

Program Element Affected: Element 3 - Parameters Monitored or Inspected, and Element 4 - Detection of Aging Effects

6. Revise implementing procedures for non-code closure bolting inspections to include methods for detecting aging effects and indications of joint leakage, as well as inspection parameters for items such as lighting, distance, and offset, which provide an adequate examination.

Program Element Affected: Element 4 - Detection of Aging Effects

7. Revise implementing procedures to require, where practical, identified degradation to be projected until the next scheduled inspection. Results will be evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation. For sampling-based inspections, results will be evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, frequency) will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate and extent of degradation.

Program Element Affected: Element 5 - Monitoring and Trending

8. Revise implementing procedures to establish plant-specific acceptance criteria for alternative inspections or testing for submerged closure bolting or closure bolting where the piping systems contains air or gas for which leakage is difficult to detect, such as: soap bubble testing, thermography, monitoring of pressure decay, or torque checks to the extent that the bolting is not loose.

Program Element Affected: Element 6 - Acceptance Criteria

9. Revise implementing procedures to require that if a bolted connection for pressure-retaining components is reported to be leaking, follow-up periodic visual inspections will be conducted until the leak is corrected. If the leak rate is increasing, more frequent inspections are warranted. The effects of leakage from bolted connections that have an intended function identified in 10 CFR 54.4(a)(2) will be evaluated for its impact on components with an intended function identified in 10 CFR 54.4(a)(1) and located within the vicinity of the leaking bolted connection.

Program Element Affected: Element 7 - Corrective Actions

10. Revise implementing procedures to require, for sampling-based inspections, for a situation in which an acceptance criterion for allowable degradation is exceeded, and the aging effect causing the degradation for the material/environment combination is not corrected by repair or replacement, that additional inspections will be performed. The number of additional inspections will be determined in accordance with the Corrective Action Program; however, no fewer than five additional (or 20%, whichever is less) inspections will be performed of different

components having the same material/environment/aging effect combination as the component(s) that did not meet the acceptance criterion. If these subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be performed to determine the further extent of inspections. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections for all BFN units' components having the same material, environment, and aging effect combination. The additional inspections will be completed within the same interval for which the original sample-based inspections are conducted. 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.

Program Element Affected: Element 7 - Corrective Actions

<u>Operating Experience</u>

The following examples of operating experience provide objective evidence that the Bolting Integrity program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for the Bolting Integrity Program described in FSAR Section O.1.15 in support of preparing the BFN Subsequent License Renewal Application. The purpose of the program effectiveness review was to verify that the intent of the existing aging management program activities, to identify and correct, as warranted, age-related degradation of components monitored by the bolting integrity program, is being effectively implemented in the initial license renewal period of extended operation. The activities include (a) preventive measures to specify selection of bolting material and the use of lubricants and sealants, consistent with industry guidelines; and (b) in-service inspections of Class 1, 2, and 3 components in accordance with ASME Section XI, Subsections IWB, IWC, and IWD Program. The program effectiveness review was comprised of a review of inspection implementation activities to date and pertinent issues, searching for identified age-related degradation of components related to bolting integrity. Pre-period of extended operation, visual inspection results, and resulting issues were also reviewed. In accordance with procedures, a Notification of Indication (NOI) is initiated and a Condition Report (CR) is written for each rejected ASME Section XI Inservice Inspection examination. The resolution and assessment for additional and successive examinations are addressed through the NOI process required by procedure. These assessments are documented in the site final reports and Owners Activity Reports. The Owners Activity Reports are submitted to the NRC within 90 days of concluding refueling outages. Since 2006, there have been thousands of inspections completed on each unit concerning bolting integrity. Studs, Bolts Nuts and Washers have been inspected either visually or ultrasonically tested. When these components do not meet acceptance criteria, work orders are initiated and the components are replaced. A review of the CRs and NOIs issued related to bolting have determined that the Studs, Bolts, Nuts and Washers that are found defective, have been the result of issues caused by maintenance activities such as damage done during disassembly or are the result of over-torquing during assembly. There were no age-related failures of bolting discovered during the evaluations or CRs reviewed. There was a Self-Assessment performed for the entire Aging Management Program, which was BFN License Renewal Self-Assessment 2022. This assessment did not identify any deficiencies with the Bolting Integrity Program.

   This operating experience provides objective evidence that initial license renewal program commitments are being properly implemented and deficiencies identified with closure bolting on pressure-retaining components are entered into the Corrective Action Program. The

Corrective Action Program is effective in evaluating and correcting degraded conditions. Continued implementation of the Bolting Integrity program will assure degraded conditions will be identified and corrected during the subsequent period of extended operation.

2. While reviewing a valve drawing in March 2020, it was discovered that a check valve has a pressure-retaining valve body bolting that should have been included into the BFN ASME Section XI program. Additionally, Items 18, 19, and 28 on the valve drawing should have been classified as Category B-G-2, Item Number B7.70. As a result, the required VT-1 visual examination was subsequently performed while the component was disassembled in Unit 3 refueling outage U3R19 (spring of 2020). The inspection revealed no recordable indications and was determined to be acceptable. A Condition Report was generated to drive correction of the BFN ISI Program, ISI Data Base, and ISI Drawings. It was also used as an extent of condition to review this issue on the other units. All valves listed as having no B-G-2 bolting, were reviewed as part of this extent of condition. A total of five components, including the originally identified check valve, were revised to include B-G-2 bolting as part of the ISI Program. The BFN ISI Program, ISI Database, and ISI Drawings were revised for these components.

   This operating experience provides objective evidence that ASME Section XI requirements are being reviewed, and when issues are discovered, the Corrective Action Program is used to correct the deficient conditions associated with the Bolting Integrity Program. This will also support effectively manage aging by identifying and correcting degradation prior to failure or loss of intended function during the subsequent period of extended operation.

3. During performance of a work order, in October 2020, while removing steel supports associated with a Unit 1 flow control valve, a nut was discovered missing. The issue was entered into the Corrective Action Program and a replacement nut and bolt were obtained and installed. During the closure review of the work order, a questioning attitude by craft supervisor noticed that statements in the work order required returning the work order to planning prior to installing new bolting for addition of ASME Section XI requirements, which include a ASME Section XI Repair and Replacement plan, and Pre-Service Examination. Since no Repair and Replacement plan was added to this work order prior to installation of bolt and nut, the Pre-Service Examination requirements were not performed. A CR was written to document that the work order was sent back to planning to be revised (Revision 1) to include ASME Section XI Repair and Replacement plan and Pre-Service Examination requirements. Due the appearance of loss of traceability, the installed bolt and nut were removed and discarded. A visual inspection was performed, in accordance with the Pre-Service Examination requirements on the new bolt and nut. After the satisfactory inspection, the new bolt and nut were properly installed.

   This operating experience provides objective evidence that ASME Section XI requirements are being reviewed during documentation closure, and any conflicts are being resolved using the Corrective Action Program to ensure Bolting Integrity Program requirements are maintained. This will support effectively managing aging by correcting possible degradation issues prior to failure or loss of intended function during the subsequent period of extended operation.

<u>Conclusion</u>

The enhanced Bolting Integrity program will provide reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.11 Open-Cycle Cooling Water System

Program Description

The BFN Open-Cycle Cooling Water (OCCW) System program is an existing condition monitoring program and includes preventive measures. The program relies, in part, on implementing portions of the recommendations for the U.S. Nuclear Regulatory Commission (NRC) Generic Letter (GL) 89-13 and includes non-safety related portions of the OCCW system. The program provides reasonable assurance that the effects of aging on the OCCW (or service water) system will be managed for the subsequent period of extended operation. The program is comprised of the aging management aspects of BFN's response to NRC GL 89-13 including: (a) a program of surveillance and control techniques to significantly reduce the incidence of flow blockage problems as a result of biofouling; (b) a program to verify heat transfer capabilities of RHR heat exchangers cooled by the OCCW system; and (c) a program for routine inspection and maintenance to provide reasonable assurance that loss of material, corrosion, erosion, cracking, fouling, and biofouling cannot degrade the performance of in-scope systems serviced by the OCCW system. The program applies to components constructed of the following materials: Copper alloy (>15% Zn or >8% Al), copper alloy, stainless steel, steel and nickel alloy. BFN does not have in-scope aluminum, titanium or fiberglass components exposed to raw water. The program includes guidance beyond the requirements contained in NRC GL 89-13, such as inputs from industry reports and documents (e.g., EPRI documents) that address operating experience such that aging effects are adequately managed.

The program manages aging effects of components in raw water systems, such as service water, by using a combination of preventive, condition monitoring, and performance monitoring activities. Included in the BFN OCCW program are (a) surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, and fouling in the OCCW system or structures and components serviced by the OCCW system; (b) inspection of components for signs of loss of material, corrosion, erosion, cracking, fouling, and biofouling; and (c) testing of the heat transfer capability of the RHR heat exchangers that remove heat from components important to safety.

The program includes chemical treatment that mitigates microbiologically influenced corrosion (MIC) and buildup of macroscopic biofouling debris such as mussels and clams. The program includes flushing of infrequently used cooling loops to remove accumulations of biofouling agents, corrosion products, debris, and silt. Degradation resistant materials are used in some components in the OCCW systems.

Visual inspections in the program are used to identify fouling and provide a qualitative assessment for loss of material due to various forms of corrosion and erosion. Coatings inspections for components in the OCCW System program are addressed in the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (B.2.1.28). Polymeric and concrete components exposed to raw water are controlled by the Inspection of Water-Control Structures Associated with Nuclear Power Plants program (B.2.1.34). The OCCW System program includes the use of volumetric examinations, such as ultrasonic testing, eddy current testing, and radiography to quantify the extent of wall thinning or loss of material.

Inspections and tests contained in the BFN OCCW program are performed by personnel qualified in accordance with site procedures and programs to perform the specified task. Inspections within the scope of the American Society of Mechanical Engineers Boiler and

Pressure Vessel (ASME) Code should follow procedures consistent with the ASME Code. Non-ASME Code inspections follow site procedures that include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. Qualification of personnel performing inspections and evaluations as specified in ACI 349.3R are contained in the Inspection of Water-Control Structures Associated with Nuclear Power Plants program (B.2.1.34).

The OCCW System program includes performance of inspections for detection of aging effects on the internal portions of the embedded RHRSW pipes that run between the CCW Pump Pits to the EECW/RHRSW Pump Pits and the RHRSW sluice gate valves located in the CCW Pump Pits.

The program includes trending for the RHR heat exchangers, that are tested for heat transfer capability, to verify adequacy of testing frequencies. For other in-scope heat exchangers, that are inspected for degradation in lieu of testing, inspection results are trended to evaluate adequacy of inspection frequencies.

For buried OCCW piping and piping components, the aging effects on the external surfaces are managed by the Buried and Underground Piping and Tanks program (B.2.1.27). The internal portions of buried OCCW piping and piping components are managed by this OCCW System program. Some BFN components exposed to raw water that are not within the scope of NRC GL 89-13 are managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (B.2.1.24). Water systems for fire protection are managed by the Fire Water System program (B.2.1.16). The management of coated components exposed to raw water are controlled by the Internal Coatings/Linings for Piping, Piping Components, Heat Exchangers, and Tanks program (B.2.1.28).

Closure bolting components contained in the OCCW systems are managed by the Bolting Integrity program (B.2.1.10).

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 will be determined in accordance with the site's Corrective Action Program; however, no fewer than five additional inspections will be conducted for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less. For BFN, the additional inspections will include inspections at all the units with the same material, environment, and aging effect combination.

NUREG-2191 Consistency

The enhanced Open-Cycle Cooling Water System aging management program will be consistent with the 10 elements of aging management program XI.M20, Open-Cycle Cooling Water System, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Revise implementing procedures to include heat exchangers in the High Pressure Fire Protection (Diesel Driven Pump) System, the Control Air System, and the Control Rod Drive System.

   Program Element Affected: Element 1 - Scope of Program

2. Revise implementing procedures to include reevaluation, repair, or replacement of components that do not meet minimum wall thickness requirements. If fouling is identified, the overall effect is evaluated for reduction of heat transfer, flow blockage, loss of material, and (if applicable) chemical treatment effectiveness. For ongoing degradation mechanisms (e.g., MIC), the frequency and extent of wall thickness inspections are increased commensurate with the significance of the degradation.

   Program Element Affected: Element 7: - Corrective Actions

3. Revise implementing procedures to include the requirement that 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 inspections are conducted for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination will be inspected, whichever is less. The additional inspections include inspections at all BFN units with the same material, environment, and aging effect combination.

   Program Element Affected: Element 7: - Corrective Actions

Operating Experience

The following examples of operating experience provide objective evidence that the Open-Cycle Cooling Water System program will be effective in assuring that intended functions are maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for the Open-Cycle Cooling Water System program described in FSAR Section O.1.16. The purpose of the program effectiveness review was to verify that the existing aging management program activities are effective in identifying and correcting age-related degradation of components of the Residual Heat Removal Service Water, Emergency Equipment Cooling Water, and other raw water systems monitored by the Inspections of the Open-Cycle Cooling Water System program, are being effectively implemented in the initial license renewal period of extended operation. The program effectiveness review was comprised of a review of inspection implementation activities to date and pertinent issues in the Corrective Action Program and searching for identified age-related degradation of components related to Open-Cycle Cooling Water Systems. The program manages the effects of aging on the BFN Open-Cycle Cooling Water Systems that are within the scope of license renewal. Operating experience within the Corrective Action Program relative to raw water program activities from 2011 through 2022 was reviewed. The inspections and tests performed for raw water systems have identified age-related deficiencies associated with corrosion and fouling of internal surfaces of raw water components. These deficiencies have been identified during the performance of

periodic aging management program activities by direct visual and volumetric inspections. Low flow and heat exchanger/cooler fouling has also been identified during periodic testing and inspection. The results of these inspections were evaluated under the Corrective Action Program which provided the appropriate information to direct repair, replacement, or flushing of raw water system components. These inspections, along with the evaluation of deficiencies within the Corrective Action Program, have resulted in the effective implementation of these aging management programs.

This example provides objective evidence that existing aging management program activities are being effectively implemented to manage aging effects of in-scope raw water system piping and components, and that deficiencies associated with the implementation of the program are identified and entered into the Corrective Action Program for evaluation. Continued implementation of these activities will assure that piping and components within the scope of the programs will continue to perform their intended functions during the subsequent period of extended operation.

2. The 2022 Aging Management Program Effectiveness review also reviewed the test results of aging management program implementing procedures, including inspections to meet NRC Generic Letter 89-13 requirements. Twenty test results packages were reviewed for inspections of heat exchangers, coolers, chillers, and piping in the Residual Heat Removal Service Water, Air Conditioning, Emergency Equipment Cooling Water, Residual Heat Removal, and Emergency Diesel Generator Systems dated from 2015 to 2022. The review found that 17 of the tests resulted in no indication of corrosion, two test results found inconclusive results, and one found indications of corrosion which were evaluated and resolved in accordance with the Corrective Action Program.

   This example demonstrates that inspections are being performed in accordance with the aging management program and that components within the scope of the Open-Cycle Cooling Water System program are being properly managed for aging. This example also demonstrates that the Corrective Action Program is used effectively to identify and evaluate conditions adverse to quality.

3. The seismic restraints for all 12 Residual Heat Removal Service Water/Emergency Equipment Cooling Water pumps in the Residual Heat Removal Service Water pump pit were inspected on October 29, 2013, and October 30, 2013. The inspection was performed by divers. Degradation was noted on portions of each of the 12 seismic restraints. The degradations identified included missing or severely corroded bolting, missing or failed anchors, missing, broken, or loose clips, dented strainer screens, and the pump bell in contact with the seismic restraint. This issue was addressed in the Corrective Action Program, which resulted in an engineering evaluation to demonstrate the seismic qualification of the Residual Heat Removal Service Water/Emergency Equipment Cooling Water pumps with the seismic restraint being considered ineffective or removed. The corrective action also documented that an existing design change package was being issued, which replaced all Residual Heat Removal Service Water pumps with new pumps. The design of the new Residual Heat Removal Service Water pumps includes unique seismic restraints. An engineering calculation documented the qualification of the new seismic restraints. Pump replacement started July 15, 2015 and was completed May 7, 2021. These inspections and resulting corrective actions support operation during the current period of extended operation. These components were required to be inspected at least one additional time within 10 years of entering the period of extended operation. The additional inspection of the Residual Heat Removal Service Water pump seismic restraints was completed by a preventive maintenance activity on October 29, 2021. No indications of cracking, spalling, erosion, corrosion, gaps or other damage were noted.

The pump strainer baskets were also inspected, and marine growth was cleaned/removed as needed.

This example provides objective evidence that the existing aging management program activities are being effectively implemented to identify and manage aging effects of in-scope components serviced by raw water. Deficiencies identified during inspection activities are entered into the Corrective Action Program and appropriate corrective actions are taken to evaluate and correct the deficiencies.

4. There have been two self-assessments associated with the Browns Ferry Nuclear License Renewal programs during the period of extended operation.
   - Browns Ferry Nuclear 2020 License Renewal Self-Assessment. This assessment identified a learning opportunity associated with Open Cycle Cooling Water System aging management program commitments to perform inspections of the Residual Heat Removal Service Water pump pit supply piping at least one additional time within 10 years of entering the period of extended operation. At the time of the assessment eight preventive maintenance (PM) activities had been assigned for these inspections. However, detailed work order documents had not been prepared for their performance. The issue was entered into the Corrective Action Program. This resulted in the review of the PMs and their proposed schedule and a verification that they would be completed within the 10 year commitment date. As part of this Effectiveness Review, a review of the status of the eight PM activities was conducted. Two of the PM activities have been completed, four of the PMs are scheduled to be completed prior to the 10 year commitment date, and two of the PMs are scheduled to be completed after the 10 year commitment date. As a result of these findings and the findings of other aging management program effectiveness reviews, the issue was entered into the Corrective Action Program. This has resulted in corrective actions to determine a method to prioritize aging management related Work Orders (WO), a method for notification of aging management program owners of WO delays or cancellation, and the use of aging management trend codes to aide in tracking aging management issues. These actions have been completed.
   - An Aging Management Program Self-Assessment was conducted in 2022. This assessment found no specific aging management program technical issues with the Open-Cycle Cooling Water System program.

   This example demonstrates that periodic self-assessments of the Open-Cycle Cooling Water System aging management program have been performed to identify and correct program elements that need improvement to maintain the quality performance of the program.

5. During a program effectiveness review, it was identified that the first inspections after the period of extended operation had been scheduled to be performed later than required by the program. The program procedure requires visual inspection of the six Residual Heat Removal Service Water sluice gate valves for flow restriction, loss of material due to corrosion, and evidence of cracking. These inspections are to be commenced prior to the expiration of the initial 40-year license for each unit and conducted every ten years thereafter throughout the period of extended operation. The initial inspections were completed as required, however the Periodic Maintenance data base incorrectly started the 10-year clock at the date of entry into the period of extended operation, as opposed to the date of the previous inspection. This issue was entered into the Corrective Action Program as an issue generic to several aging management programs and corrective actions have been taken to review all aging management implementing procedures, including preventive maintenance activities, against the requirements of the respective aging management program basis documents. The result is that the inspections of the Residual Heat Removal Service Water sluice gate valves have

been added to existing Condenser Circulating Water Pit inspections for each BFN unit. All inspections that were scheduled late have been completed.

This operating experience provides objective evidence that the Open-Cycle Cooling Water System aging management program effectively monitors required equipment to assure that they will be able to continue to perform their intended functions and that appropriate aging management will be performed during the subsequent period of extended operation.

Conclusion

The enhanced Open Cycle Cooling Water program will provide reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.12 Closed Treated Water Systems

Program Description

The BFN Closed Treated Water Systems (CTWS) is an existing program that manages the aging effects of loss of material due to corrosion and reduction of heat transfer due to fouling of the internal surfaces of piping, piping components, piping elements and heat exchanger components fabricated from any material and exposed to treated water. The BFN CTWS program is a mitigation program that also includes condition monitoring to verify the effectiveness of the mitigation activities. The program includes: (a) water treatment, including the use of corrosion inhibitors, to modify the chemical composition of the water such that the function of the equipment is maintained and such that the effects of corrosion are minimized; (b) chemical testing of the water to demonstrate that the water treatment program maintains the water chemistry within acceptable guidelines; and (c) inspections to determine the presence or extent of degradation.

The BFN CTWS program includes systems that contain demineralized water that is treated with corrosion inhibitors. Corrosion inhibitors are not added to the Shutdown Board Room (SDBR) (Air Conditioning) and Variable Frequency Drive (Reactor Recirculation) systems. These systems meet the industry guidance for pure water systems.

The BFN Closed Treated Water Systems program mitigates the aging effects of loss of material, cracking, and reduction of heat transfer through water treatment. The water treatment program includes corrosion inhibitors and is designed to maintain the function of associated equipment and minimize the corrosivity of the water and the accumulation of corrosion products that can foul heat transfer surfaces.

The BFN Closed Treated Water Systems program monitors water chemistry parameters (preventive monitoring) and the condition of surfaces exposed to the water (condition monitoring).

The BFN Closed Treated Water Systems program chemistry parameters (such as the concentration of iron, copper, silica, oxygen, and hardness, alkalinity, specific conductivity, and pH) are monitored in the BFN Chemistry Program to optimize water chemistry which prevents loss of material and cracking due to corrosion and SCC. The specific water chemistry parameters monitored and the acceptable range of values for these parameters are in accordance with the

EPRI 3002000590, Revision 2, “Closed Cooling Water Chemistry Guideline,” which is used in its entirety for the water chemistry control or guidance.

The visual appearance of surfaces is evaluated for evidence of loss of material. The results of surface or volumetric examinations will be evaluated for surface discontinuities indicative of cracking. The heat transfer capability of heat exchanger surfaces is evaluated by either visual inspections to determine surface cleanliness, or functional testing to verify that design heat removal rates are maintained.

In the BFN Closed Treated Water Systems program, aging effects will be detected through water testing and periodic inspections. Water testing determines whether the water treatment program effectively maintains acceptable water chemistry. Water testing frequency is conducted in accordance with the BFN Chemistry Program.

Because the control of water chemistry may not be fully effective in mitigating the aging effects, inspections will be conducted. The BFN Closed Treated Water Systems program will include visual inspections of internal surfaces that are conducted whenever the system boundary is opened. At a minimum, in each 10-year period during the subsequent period of extended operation, a representative sample of 20 percent of the population (defined as components having the same material, water treatment program, and aging effect combination) or a maximum of 25 components per population at each unit will be inspected using techniques capable of detecting loss of material, cracking, and fouling, as appropriate. The 20 percent minimum is surface area inspected unless the component is measured in linear feet, such as piping. In that case, any combination of 1-foot length sections and components can be used to meet the recommended extent of 25 inspections.

If degradation is identified in the initial sample, additional samples will be inspected to determine the extent of the condition.

The ongoing opportunistic visual inspections will be credited towards the representative samples for the loss of material and fouling; however, surface or volumetric examinations will be used to detect cracking. The inspections will focus on the components most susceptible to aging because of time in service and severity of operating conditions, including locations where local conditions may be significantly more severe than those in the bulk water (e.g., heat exchanger tube surfaces).

Inspections are performed by personnel qualified in accordance with plant procedures and programs to performed the specified task. Inspections will be conducted in accordance with procedures consistent with applicable ASME code requirements. If there are no ASME code requirements, inspections will be conducted in accordance with site procedures, which will include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

The BFN Closed Treated Water Systems program evaluates water chemistry data against the standards contained in the selected water treatment program. These data are trended, so corrective actions are taken, based on trends in water chemistry, prior to loss of intended function. Where practical, identified degradation will be projected until the next scheduled 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 BFN Closed Treated Water Systems program includes controls that ensure water chemistry concentrations are maintained within the limits specified in the selected industry standard documents. Due to the water chemistry controls, no age-related degradation is expected. Therefore, any detectable loss of material, cracking, or fouling is evaluated in the Corrective Action Program.

Water chemistry concentrations that are not in accordance with the closed treated water systems contained in the BFN Chemistry Program are returned to the normal operating range within the prescribed time frame for each action level in the BFN Chemistry Program. If fouling is identified, the overall effect is evaluated for reduction of heat transfer, flow blockage, and loss of material.

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 will be determined in accordance with the site's Corrective Action Program; however, no fewer than five additional inspections will be conducted for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less. For BFN, the additional inspections will include inspections at all the units with the same material, environment, and aging effect combination.

NUREG-2191 Consistency

The enhanced Closed Treated Water Systems aging management program will be consistent with the 10 elements of aging management program XI.M21A, Closed Treated Water Systems, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Revise implementing procedures to manage the effects of cracking due to stress corrosion cracking in closed treated water systems.

   Program Element Affected: Element 1 - Scope of Program

2. Revise implementing procedures to include surface or volumetric examinations. The results of these examinations will be evaluated for surface discontinuities indicative of cracking.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

3. Revise implementing procedures to include inspections of Closed Treated Water Systems components for the detection of loss of material, cracking, and fouling.

   Program Element Affected: Element 4 - Detection of Aging Effects

4. Revise implementing procedures to include visual inspections of internal surfaces that are conducted whenever the system boundary is opened. At a minimum, in each 10-year period during the subsequent period of extended operation, a representative sample of 20 percent of the population (defined as components having the same material, water treatment program, and aging effect combination) or a maximum of 25 components per population at each unit will be inspected using techniques capable of detecting loss of material, cracking, and fouling, as

appropriate. The 20 percent minimum is surface area inspected unless the component is measured in linear feet, such as piping. In that case, any combination of 1-foot length sections and components can be used to meet the recommended extent of 25 inspections.

Program Element Affected: Element 4 - Detection of Aging Effects

5. Revise implementing procedures to include expansion of the sample population if degradation is identified in the initial population in order to determine the extent of the condition.

Program Element Affected: Element 4 - Detection of Aging Effects

6. Revise implementing procedures to credit ongoing opportunistic visual inspections towards the representative samples for the loss of material and fouling; however, surface or volumetric examinations will be used to detect cracking. These inspections focus on the components most susceptible to aging due to time in service and severity of operating conditions, including locations where local conditions may be significantly more severe than those in the bulk water (e.g., heat exchanger tube surfaces).

Program Element Affected: Element 4 - Detection of Aging Effects

7. Revise implementing procedures to include inspections and tests are performed by personnel qualified in accordance with applicable ASME code requirements.

Program Element Affected: Element 4 - Detection of Aging Effects

8. Revise the implementing procedures to include if there are no ASME code requirements, inspections will be conducted in accordance with site procedures, which will include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

Program Element Affected: Element 4 - Detection of Aging Effects

9. Revise implementing procedures to include, where quantitative data is available, identified degradation to be projected until the next scheduled 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.

Program Element Affected: Element 5 - Monitoring and Trending

10. Revise implementing procedures to include, if one of the inspections does not meet acceptance criteria, the cause of the aging effect for each applicable material and environment to be either corrected by repair or replacement for all components constructed of the same material and exposed to the same environment or additional inspections will be conducted. The number of increased inspections will be determined in accordance with the site's Corrective Action Program; however, no fewer than five additional inspections will be conducted for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less. 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 ensure corrective actions appropriately address the associated causes. For BFN, the additional inspections will include inspections at all the units with the same material, environment, and aging effect combination.

Program Element Affected: Element 7 - Corrective Actions

Operating Experience

The following examples of operating experience provide objective evidence that the Closed Cycle Cooling Water Systems program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for the Closed-Cycle Cooling Water System program described in FSAR Section O.1.17. The purpose of the program effectiveness review was to verify that the existing aging management program activities, to identify and correct, age-related degradation of components monitored by the Inspections of the Closed-Cycle Cooling Water System program, are being effectively implemented in the initial license renewal period of extended operation. The program effectiveness review was comprised of a review of implementation activities which consist of results of monitored preventive actions, Chemistry results, equipment performance results, surveillances tests, and inspections of coolers and heat exchangers related to Closed-Cycle Cooling Water Systems. The effectiveness review also included pertinent issues in the Corrective Action Program, searching for identified age-related degradation of components related to Closed-Cycle Cooling Water Systems. The program manages the effects of aging on the BFN Closed-Cycle Cooling Water Systems which include the Reactor Building Closed Cooling Water, Diesel Generator Cooling Water, Control Room and Shutdown Board Room Chilled Water, Recirculation Pump Variable Frequency Drive Cooling Water and Diesel Fire Pump Cooling Water systems that are within the scope of license renewal. This Aging Management Program Effectiveness review looked at the results of inspections and activities for the years from 2012 to 2022. Although some instances of system leakage did occur in closed cooling water systems, it was identified prior to loss of system function and corrected through the Corrective Action Program. Closed cooling water chemistry was either maintained within industry guidelines, or if chemistry parameters exceeded an industry action level, the issue was entered into the Corrective Action Program and actions were taken to restore the parameter to within industry guidelines. The activities to monitor and control closed cooling water chemistry has resulted in the effective implementation of this aging management program. Chemistry control is monitored and maintained by a robust sampling and testing program. The majority of the issues documented were associated with excursions of chemistry parameters. Actions to restore the associated parameter(s) and evaluate causes were documented along with any follow-up testing results which were required.

   This example provides objective evidence of aging management program effectiveness during the first period of extended operation and provides objective evidence that the continued implementation of the Closed-Cycle Cooling Water System aging management program will effectively manage aging prior to failure or loss of intended function during the subsequent period of extended operation.

2. A review of Closed Treated Water Systems test results conducted between 2012 through 2022 was performed. The following summarizes the review.
   - Ten diesel driven fire pump inspection test result packages were reviewed. This performance test activity has a 18 month frequency and this sample of results reviewed represents the entire 10 year duration of testing. All testing was found to be acceptable; no issues were documented in the Corrective Action Program.
   - Five control room air conditioning system performance results packages were reviewed. This performance test activity has a 24 month frequency and this sample of results reviewed represents the entire 10 year duration of testing. All testing was found to be acceptable; no issues were documented in the Corrective Action Program.

- Six drywell atmosphere cooling system test result packages were reviewed. This performance test has a once per refueling outage frequency and this sample of results represents two performances on each BFN unit during the 10 year duration reviewed. All testing was found to be acceptable; no issues were documented in the Corrective Action Program.
- Preventative Maintenance (PM) activities for performance testing of High Pressure Fire Pump (HPFP) Diesel Engine were reviewed. All testing was found to be acceptable; no issues were documented in the Corrective Action Program.
- PM activities for the performance of Reactor Building Closed Cooling Water Heat Exchanger Maintenance were reviewed. All PMs are up to date and scheduled to be completed as required. No issues were documented in the Corrective Action Program.
- PMs for the performance of Standby Diesel Engine Water Coolers Disassembly, Inspection, Rework, and Reassembly, and Standby Diesel Engine Aftercooler Disassembly, Inspection, Rework, and Reassembly, were reviewed. All PMs are up to date and scheduled to be completed as required. No issues were documented in the Corrective Action Program.

This example demonstrates that Closed Cycle Cooling Water System inspections are being performed in accordance with the aging management program and that components and equipment on all units within the scope of the program are being effectively managed for aging prior to failure or loss of intended function during the subsequent period of extended operation.

3. Four Control Room Air Conditioning System test performances since the beginning of the period of extended operation (end of 2013) identified issues with out of specification results or incomplete results. These issues were entered into the Corrective Action Program. Three identified deficiencies were equipment related issues, a leaking poly flow line, a failed air operated valve positioner on a temperature control valve, and low chilled water flow which was corrected by adjustment. One test performance resulted in a Condition Report (CR) being initiated to document that only a partial performance, Train B only, was completed. This CR resulted in the completion of the procedure with acceptable results. The partial performance of Train B was completed in June 2018 and Train A was completed in September 2018. During the April 28, 2022, performance of preventive maintenance activities for the HPFP Diesel Engine, it was identified that the engine coolant cap area was showing signs of corrosion. This issue was documented in the Corrective Action Program.

   These examples provides objective evidence that the existing aging management program activities are being effectively implemented to identify and manage aging effects of in-scope components serviced by closed cycle cooling water. Deficiencies identified during inspection activities are entered into the Corrective Action Program and appropriate corrective actions are taken to evaluate and correct the deficiencies prior to failure or loss of intended function during the subsequent period of extended operation.

4. A self-assessment specific to the Closed-Cycle Cooling Water program was conducted in 2016. The purpose of the assessment was to determine if the BFN Chemistry Department program procedure was aligned with the newest revision of the EPRI Closed Cooling Water Chemistry Guidelines (Revision 2, December 2013), concerning sampling frequency, monitoring parameters and corrosion control treatment options. Two Learning Opportunities were identified:

   - Benchmark information indicated some plants use only demineralized water and an oxygen scavenger for their closed/chilled water systems. No other chemicals were used for corrosion protection. A CR was initiated to obtain more information on these closed cooling water system chemical treatment methods to determine if their use of demineralized water only would be beneficial at BFN. An evaluation was performed which determined, after consultation with the Corporate Functional Area Managers for heat exchangers, that continued chemical corrosion protection for closed cooling/chilled water systems was the appropriate method for BFN.

- The BFN Chemistry Department currently uses the department database to generate a target report for closed cooling water systems to identify which of the diagnostic parameters are approaching the Good Practice Value. This enables adjustments to be made before the Good Practice Value is reached giving more margin to prevent going out of limits. This process is not procedurally driven. A CR was initiated to determine if this practice should be placed in procedure for sustainability. The associated corrective action evaluated the issue and determined that the practice is above and beyond the Good Practice Values required by procedure and EPRI guidelines. The CR resulted in the practice being controlled by a department directive.

There have also been two self-assessments associated with the Browns Ferry Nuclear License Renewal programs during the period of extended operation, a Browns Ferry Nuclear 2020 License Renewal Self-Assessment and an Aging Management Program 2022 Self-Assessment. No specific aging management program technical issues with the Closed-Cycle Cooling Water System Program were found.

This example demonstrates that periodic self-assessments of the Closed Cycle Cooling Water System aging management program have been performed to identify and correct program elements that need improvement to maintain the quality performance of the program.

Conclusion

The enhanced Closed Treated Water Systems program will provide reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.13 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

Program Description

The BFN Inspection of Overhead Heavy Load and Light Load (Related To Refueling) Handling Systems aging management program is an existing condition monitoring program that manages the effects of loss of material due to corrosion and wear, cracking, deformation, and indications of loss of preload for load handling bridges, structural members, structural components, and bolted connections. Procedures and controls implement the guidance on the control of overhead heavy load cranes specified in NUREG-0612, “Control of Heavy Loads at Nuclear Power Plants.” The program utilizes periodic visual inspections as described in the ASME B30 series of standards for inspection, detection of aging effects, evaluation, and repair of aging effects.

This program manages aging effects of cranes and hoists that are within subsequent license renewal, including the reactor building crane, refuel platform crane, numerous equipment handling cranes, hoists, and monorails. Also within the scope of the program are handling systems that handle “light” loads including mobile lifts/cranes, lifting lugs and monorail devices, if they have the potential to directly or indirectly cause a release of radioactive materials as described in NUREG-0612.

Inspection frequency and scope is in accordance with the recommendations for periodic inspection within the ASME B30 series of standards. For the Refuel Platform and Reactor Building Crane that are infrequently in service, periodic inspections are performed once every refueling cycle and just prior to use. Other in scope load handling systems are to have monthly (frequent) and annual (periodic) inspections. Aging effects are identified by inspection.

NUREG-2191 Consistency

The enhanced BFN Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems aging management program will be consistent with the 10 elements of aging management program XI.M23, The BFN Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Revise the implementing procedures to ensure surface conditions are monitored by visual inspection to provide reasonable assurance that 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.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

2. Revise the implementing procedures to ensure bolted connections are monitored by visual inspection to provide reasonable assurance that loss of material, cracking, and loose bolts, missing or loose nuts, and other conditions indicative of loss of preload are not occurring.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

3. Revise implementation procedures to ensure aging effects will be detected for bridges, structural members, and structural components by visually inspecting for loss of material due to general corrosion; deformation; cracking, and wear.

   Program Element Affected: Element 4 - Detection of Aging Effects

4. Revise implementation procedures to ensure aging effects will be detected for bolted connections by visually inspecting for loss of material due to general corrosion; cracking; and loose or missing bolts or nuts, and other conditions indicative of loss of preload.

   Program Element Affected: Element 4 - Detection of Aging Effects

5. Revise implementation procedures to require visual inspection activities of in-scope load handling systems to be performed by qualified personnel.

   Program Element Affected: Element 4 - Detection of Aging Effects

6. Revise implementation procedures to ensure any visual indication of loss of material, deformation, or cracking, and any visual sign of loss of bolting preload will be evaluated for acceptance criteria according to ASME B30.2-1976 as well as other appropriate standards in the ASME B30 series including B30.11-1988, “Monorails and Underhung Cranes,” B30.16-1973, “Overhead Underhung and Stationary Hoists,” B30.10-1975, “Hooks,” and B30.17-1980, “Cranes and Monorails With Underhung Trolley or Bridge.”

   Program Element Affected: Element 6 - Acceptance Criteria

7. Revise implementing procedures to ensure any repairs to in-scope load handling systems will be performed as specified in ASME B30.2-1976 as well as other appropriate standards in the ASME B30 series including B30.11-1988, B30.16-1973, B30.10-1975, and B30.17-1980.

   Program Element Affected: Element 7 - Corrective Action

Operating Experience

The following examples of operating experience provide objective evidence that the Inspection of Overhead Heavy Load and Light Load Handling Systems program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, an Aging Management Program effectiveness review was performed for the Inspection of Overhead Heavy Load and Light Load Handling program described in FSAR Section O.1.18 in support of preparing the BFN Subsequent License Renewal Application. The purpose of the program effectiveness review was to verify that the intent of the existing aging management program activities, to identify and correct, as warranted, age-related degradation of components monitored by the Inspection of Overhead Heavy Load and Light Load Handling program, is being effectively implemented in the initial license renewal period of extended operation. The original activities included crane inspections to verify structural integrity of crane components. The program consists of visual inspections to assess the condition of in-scope crane components and functional tests to assure the in-scope cranes capability. The program effectiveness review was comprised of a review of inspection implementation activities to date and pertinent issues in the Corrective Action Program, searching for identified age-related degradation of components related to Load Handling. Pre-period of extended operation, visual inspection results, and resulting issues in the Corrective Action Program were also reviewed. The program manages the effects of general corrosion on the crane and trolley structural components for those cranes that are within the scope of license renewal, and the effects of wear on the rails in the rail system. The results of the review did not reveal any new or unexpected aging effects or trends. The Corrective Action Program review did not identify any structural issues or passive age related issues with either the reactor building overhead crane or the refuel bridge crane. The issues that were found were related to active components, such as bearings, wheel alignments, and electrical motors, breakers, and relays. The reviewed work orders indicate normal preventative maintenance is being performed. The Preventive Maintenance Program includes inspections that are conducted to identify indications of corrosion and cyclic fatigue. For in-scope cranes, no unacceptable visual indications of loss of material due to corrosion or wear and no cyclic fatigue related defects have been documented.

   A Self-Assessment was performed for the entire Aging Management Program, the 2022 BFN License Renewal Self-Assessment. This assessment did not identify any deficiencies associated with the Inspection of Overhead Heavy Load and Light Load Handling program. The aging management program effectiveness review determined that the program is being implemented as described in FSAR Section O.1.18.

   This operating experience example provides objective evidence that periodic visual inspections and the Corrective Action Program are effectively managing the aging effects of the handling systems within the scope of license renewal and that continued implementation of the Inspection of Overhead Heavy Load and Light Load Handling Systems aging management program will assure that these handling systems will continue to perform their intended functions during the subsequent period of extended operation.

2. In February 2022, “the first of shift” inspection of the reactor building overhead crane identified that the main hoist was not working. Upon further inspection, when it was attempted to

operate the main hoist, it would trip out the other controls for the crane. Maintenance personnel identified a damaged communication cable to the main hoist encoder on the Unit 1 Reactor Building Crane. The cable was replaced, and the crane returned to operable status.

This example provides objective evidence that periodic inspections are effective in identifying degraded conditions and that the Corrective Action Program is effective in evaluating the conditions and implementing repair activities to correct the conditions.

3. In June 2014, during the weekly inspection of the Unit 1 Refuel Bridge Crane, it was identified that the outer jackets on the electrical cables that go to the main hoist console were becoming dry/brittle. The electrical cables were subsequently replaced.

   This example provides objective evidence that periodic inspections are effective in identifying degraded conditions and that the Corrective Action Program is effective in evaluating the conditions and implementing repair activities to correct the conditions.

4. During building rounds conducted by Operations personnel in May 2019, an unrestrained jib crane was identified in the Unit 3 Reactor Building. This unrestrained crane could potentially strike plant equipment during a seismic event. The jib crane was then improperly “tied off” by using the chain fall tied to a drain line. Civil engineering personnel worked with maintenance personnel to evaluate the situation. It was determined that the correct action would be to secure the jib crane to an eye bolt secured into the concrete column. It was also discovered that there is no guidance showing approved tie off points for jib cranes in the associated procedure. Civil engineering personnel initiated a condition report to revise the associated procedure to provide proper direction for securing jib cranes in the absence of direction provided in plant drawings. The procedure was subsequently revised to add direction for securing jib cranes.

   This example provides objective evidence that equipment conditions are being monitored, and when those conditions determine that there is a lack of guidance for proper use, the Corrective Action Program is utilized to ensure that guidance is provided in the procedures.

Conclusion

The enhanced Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.14 Compressed Air Monitoring

Program Description

The Compressed Air Monitoring Program consists of condition monitoring (inspection and testing of the system) and preventive monitoring (air quality at various locations in the system is monitored to ensure that oil, water, rust, dirt, and other contaminants are kept within specified limits).

The Compressed Air Monitoring Program is based on NRC GL 88-14, “Instrument Air Supply System Problems Affecting Safety-Related Equipment,” and the Institute of Nuclear Power Operations Significant Operating Experience Report 88-01, “Instrument Air System Failures.” The Compressed Air Monitoring Program also incorporates provisions conforming to the guidance of the EPRI TR-108147, “Instrument Air Systems, A Guide for Power Plant

Maintenance Personnel." The program incorporates the guidelines of ANSI/ISA-S7.0.01-1996, "Quality Standard for Instrument Air," and EPRI TR-108147, "Compressor and Instrument Air System Maintenance Guide," and will be enhanced using the guidance in ASME OM-2012, Division 2, Part 28, "Performance Testing of Instrument Air Systems in Light-Water Reactor Power Plants."

Program activities include air quality checks at various locations to ensure the dew point, particulates, and hydrocarbons are maintained within specified limits and includes inspections of the internal surfaces of compressed air system components for signs of loss of material due to corrosion. Air quality test data is analyzed against established acceptance criteria. Trending is performed to ensure aging effects on passive components are identified. The effects of corrosion and presence of contaminants are detected during periodic tests, and preventive maintenance inspections of compressed air system components. Inspections of accessible internal surfaces of components provides assurance that the systems within the scope of subsequent license renewal will perform their intended function.

Results from inspections are compared with established acceptance criteria to provide for timely detection of aging effects. The monitoring methods are effective in detecting the applicable aging effects, and the frequency of monitoring will be adequate to prevent significant age-related degradation. Deficiencies are documented in the Corrective Action Program and evaluations are performed for test or inspection results that do not satisfy established criteria. The Corrective Action Program ensures that the conditions adverse to quality are promptly corrected. The site Corrective Action Program is implemented in accordance with the requirements of the 10 CFR Part 50, Appendix B quality assurance program.

Compressed Air Monitoring Program will be enhanced to include the Emergency Diesel Generator Starting Air System to ensure that periodic inspection and replacement of components are performed to prevent or mitigate aging degradation.

<u>NUREG-2191 Consistency</u>

The enhanced Compressed Air Monitoring Program will be consistent with the 10 elements of aging management program XI.M24, Compressed Air Monitoring Program, specified in NUREG-2191.

<u>Exceptions to NUREG-2191</u>

None.

<u>Enhancements</u>

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Revise implementing procedures to manage the aging effects of loss of material due to corrosion in compressed air system components located downstream of the compressed air system air dryers, or for components exposed to an internal gas environment (e.g., nitrogen-filled accumulators).

   Program Element Affected: Element 1 - Scope of Program

2. Revise implementing procedures for Compressed Air Monitoring Program to include the Emergency Diesel Generator Starting Air System.

   Program Element Affected: Element 1 - Scope of Program

3. Revise implementing procedures to incorporate guidelines for moisture and other corrosive contaminants limits based on ASME OM-2012, Division 2, Part 28, “Performance Testing of Instrument Air Systems in Light-Water Reactor Power Plants,” for inspection frequency and inspection methods.

   Program Element Affected: Element 2 - Preventative Actions

4. Revise implementing procedures to include opportunistic visual inspections of accessible internal surfaces are performed for signs of corrosion and abnormal corrosion products that might indicate a loss of material within the system.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

5. Revise implementing procedures to add opportunistic visual inspections of component internal surfaces exposed to an air-dry environment will be performed for signs of loss of material due to corrosion.

   Program Element Affected: Element 4 - Detection of Aging Effects

6. Revise implementing procedures to require qualification for personnel conducting visual inspection in accordance with site procedures.

   Program Element Affected: Element 4 - Detection of Aging Effects

7. Revise implementing procedures to ensure in-line dew point will be checked daily to determine whether moisture content is within the recommended range.

   Program Element Affected: Element 4 - Detection of Aging Effects

8. Revise implementing procedures to require trending of dew points being monitored and check for unusual trends in accordance with guidelines based on ASME OM-2012, Division 2, Part 28.

   Program Element Affected: Element 5 - Monitoring and Trending

9. Revise implementing procedures to ensure that effects of corrosion are monitored by visual inspection. Test data are analyzed and compared to data from previous tests to provide for the timely detection of aging effects on passive components.

   Program Element Affected: Element 5 - Monitoring and Trending

10. Revise implementing procedures to perform visual inspections which will ensure internal surfaces do not show signs of corrosion (general, pitting, and crevice) that could indicate the potential loss of function of the component. Suppliers' certifications can be used to demonstrate that bottled gases meet acceptable quality standards.

    Program Element Affected: Element 6 - Acceptance Criteria

11. Revise implementing procedures to require corrective actions to be taken if any parameters, such as moisture content in the system air, are out of acceptable ranges, or if corrosion is identified on internal surfaces.

    Program Element Affected: Element 7 - Corrective Actions

<u>Operating Experience</u>

The following examples of operating experience provide objective evidence that the Compressed Air Monitoring program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for the Inspection of Compressed Air Monitoring Program described in FSAR Section O.1.19 in support of preparing the BFN Subsequent License Renewal Application. The purpose of the program effectiveness review

was to verify that the existing aging management program activities, to identify and correct, as warranted, age-related degradation of components monitored by the Compressed Air Program, are being effectively implemented in the initial license renewal period of extended operation. The program includes inspection, monitoring, and testing of the entire system, including frequent leak testing of valves, piping, and other system components, and preventive monitoring that checks air quality at various locations in the system to ensure that oil, water, rust, dirt, and other contaminants are kept within the specified limits. The program effectiveness review was comprised of a review of inspection implementation activities to date and pertinent issues in the Corrective Action Program, searching for identified age-related degradation of components related to Compressed Air System. Pre-period of extended operation, visual inspection results, and resulting issues in the Corrective Action Program were also reviewed. The review identified that the compressed air monitoring issues are related to deficiencies discovered through the preventive maintenance activities or surveillance testing as well as observations by personnel in the plant. These issues were corrected via the corrective action and work order processes. The Compressed Air Monitoring Program consists of 13 implementing procedures for periodic inspections/tests that are conducted on control air systems. Results from recent performance of the Compressed Air Monitoring program inspections/tests are as follows:

- The dewpoint test and purge control quarterly test results indicate that when the acceptance criteria are not met, Condition Reports are written and the conditions repaired.
- Control air sampling data has not shown any issues with the sampling process. Occasionally moisture was found in sample lines and removed.
- Control air consumption tests have been completed satisfactorily with no issues.
- During the 2022 Unit 3 outage, a few leaks were identified during testing. These leaks were repaired. During the previous two Unit 3 outages, these same tests were completed satisfactorily, with no issues identified.
- During the Unit 2 outage, completed in 2021, a couple of failed check valves were identified during testing. These check valves were replaced. During the previous two Unit 2 outages, testing was completed satisfactorily, with no issues identified.
- During the Unit 1 outage, completed in 2020, a couple of leaks on the connections between the accumulator and actuator were identified during testing. The leaks were repaired and all tests were completed satisfactorily. During the previous two Unit 1 outages, a couple of leaks and a check valve that needed replacement were identified during tests. These leaks were repaired and the check valve was replaced.

There was a Self-Assessment done for the entire Aging Management Program, which was BFN License Renewal Self-Assessment 2022. This assessment did not identify any deficiencies associated with the Compressed Air Monitoring Program. The operating experience relative to the Compressed Air Monitoring program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including loss of material. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. Periodic assessments of the Compressed Air Monitoring program are performed to identify the areas that need improvement to maintain effective performance of the program.

This operating experience provides objective evidence that implementation of the Compressed Air Monitoring program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

2. In November 2020, participation in the BWR Owners Group identified that a Fluke Sonic Industrial Imager was helpful in identifying air and vacuum leaks in the plant. The equipment can detect leaks from over 100 feet away and can be used in high noise areas where air leaks cannot be heard. Use of this device saves time and dose when performing drywell control air leak checks and CRD accumulator and scram valve air leaks. The Fluke Sonic Industrial Imager was purchased and has been used extensively to locate control air leaks in the plant.

   This operating experience provides objective evidence that the Compressed Air Monitoring Program uses information gained from external operating experience, to identify and correct control air leaks prior to loss of intended function.

3. In November 2022, the Control Air system engineer was investigating work orders to verify air leaks and locations and in doing so, discovered additional air leaks. These air leaks were associated with the Control Rod Drive (CRD) system Hydraulic Control Units on Unit 3. The air leaks were found using the Fluke Sonic Industrial Imager. Each of these leaks was evaluated and determined to not currently impact the ability to maintain the scram valves fully closed.

   The operating experience relative to the Compressed Air Monitoring program, demonstrates the system engineer's inspection methods being implemented by the program have proven effective in detecting aging effects. Appropriate guidance for evaluation, repair, or replacement has been provided for locations where degradation is found.

4. In September 2020, during performance of preventive maintenance associated with dewpoint and purge control, for the Unit 2 Control Air Dryer, a dewpoint acceptance criteria was not met. The as found dewpoint was 54 degrees whereas the acceptance criteria was <35 degrees. Maintenance personnel changed out the control air dryer filters. They also disassembled, inspected, and refurbished the associated flow control valves. Maintenance personnel then satisfactorily completed Unit 2 Control Air Dryer post maintenance testing associated with dewpoint and purge control and control air consumption.

   This example provides objective evidence that the Compressed Air Monitoring program is effectively monitoring air quality, and that the Corrective Action Program is effectively used to document degraded conditions, and to correct conditions prior to loss of intended function.

<u>Conclusion</u>

The enhanced Compressed Air Monitoring program will provide reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.15 Fire Protection

<u>Program Description</u>

The Fire Protection aging management program is an existing condition and performance monitoring program that manages the identified aging effects for the fire barriers and the carbon dioxide systems and associated components in air-indoor uncontrolled and air-outdoor environments through the use of periodic inspections and functional testing to detect aging effects prior to loss of intended functions. System functional tests and inspections are performed in accordance with guidance from National Fire Protection Association Codes and Standards.

The program applies to piping, piping components, and fire barriers (doors and dampers, penetration seals and walls). Fire Protection component materials consist of carbon steel, galvanized steel, concrete, concrete block, grout, subliming and cementitious fireproofing, elastomers, and silicates.

The Fire Protection program monitoring methods are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent significant degradation. The program utilizes visual inspections of fire barrier penetration seals for signs of degradation such as loss of material, cracking/shrinking, wear, seal separation from walls and components, separation of layers of material, and changes in material properties through periodic inspection. The program specifies visual examinations of the fire barrier walls, ceilings, and floors in structures within the scope of subsequent license renewal for signs of degradation such as loss of material and cracking/spalling. Periodic visual inspections and functional tests are used to manage the aging effects of fire doors and fire damper assemblies. Inspection and testing frequencies are consistent with the Fire Protection Requirements Manual. These inspections and tests are implemented through station procedures and recurring task work orders. Personnel performing inspections are qualified and trained to perform the inspection activities. Unacceptable conditions are entered into the Corrective Action Program for proper disposition.

The program will also provide for aging management of external surfaces of the carbon dioxide fire suppression system components that are within the scope of subsequent license renewal through periodic visual inspections for corrosion that may lead to loss of material. The program includes functional testing of the carbon dioxide fire suppression system components in accordance with the Fire Protection Requirements Manual.

<u>NUREG-2191 Consistency</u>

The enhanced Fire Protection aging management program will be consistent with the 10 elements of aging management program XI.M26, Fire Protection, specified in NUREG-2191.

<u>Exceptions to NUREG-2191</u>

None.

<u>Enhancements</u>

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Revise implementing procedures to require performance of a visual inspection by fire protection qualified personnel of not less than 10 percent of each type of seal in walkdowns performed at a frequency in accordance with the NRC-approved fire protection program or at least once every refueling outage.

   Program Element Affected: Element 4 - Detection of Aging Effects

2. Revise implementing procedures to require qualification for personnel conducting visual inspection in accordance with site procedures for fire seals, fire barrier walls, ceilings, floors, and doors (e.g., wear, missing parts); fire damper assemblies; and other fire barrier materials including structural steel fire proofing.

   Program Element Affected: Element 4 - Detection of Aging Effects

3. Revise implementing procedures to require performance of visual inspections of the surface condition of the fire barriers including structural steel fire proofing at a frequency in accordance with the BFN NFPA 805 Fire Protection Requirements Manual.

   Program Element Affected: Element 4 - Detection of Aging Effects

4. Revise implementing procedures to require that results of inspections of the aging effects of cracking and loss of material on fire barrier penetration seals, fire barriers, fire damper assemblies, and fire doors be trended to provide for timely detection of aging effects so that appropriate corrective actions be taken and:
   - Where practical, identified degradation be projected until the next inspection.
   - Results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation.
   - 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.

   Program Element Affected: Element 5 - Monitoring and Trending

5. Revise implementing procedures to specify that inspection results are acceptable if there are no signs of degradation that could result in the loss of the fire protection capability due to loss of material. The specific acceptance criteria will include:
   - no visual indications (outside those allowed by approved penetration seal configurations) of cracking, separation of seals from walls and components, separation of layers of material, or ruptures or punctures of seals;
   - no significant indications of cracking and loss of material of fire barrier walls, ceilings, and floors and in other fire barrier materials;
   - no visual indications of missing parts, holes, and wear;
   - no visual indications of cracks or corrosion of fire damper assemblies;
   - no deficiencies in the functional tests of fire doors; and
   - no indications of excessive loss of material for the visual inspection of the carbon dioxide fire suppression system.

   Program Element Affected: Element 6 - Acceptance Criteria

6. Revise implementing procedures to require, if any sign of degradation is detected (during the inspection of penetration seals) within that sample, the scope of the inspection will be expanded to include additional seals in accordance with the BFN Fire Protection Requirements Manual. In addition, if any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies will be adjusted to ensure the penetration seal's intended function is maintained until at least the performance of the next inspection.

   Program Element Affected: Element 7 - Corrective Actions

Operating Experience

The following examples of operating experience provide objective evidence that the Fire Protection program will be effective in assuring that intended functions are maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for the Fire Protection Program described in FSAR Section O.1.21 in support of preparing the BFN Subsequent License Renewal Application. The purpose of the program effectiveness review was to verify that the intent of the existing aging management program activities, to identify and correct, as warranted, age-related degradation of Fire Protection Systems, is being effectively implemented in the initial license renewal period of extended operation. The Fire Protection aging management program includes a fire barrier inspection program and a diesel-driven fire pump inspection program. The fire barrier inspection program requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, and floors, and periodic visual inspection of fire rated doors to ensure that their intended function is maintained. The diesel - driven fire pump inspection program requires that the pump be periodically tested to ensure that the fuel supply line can perform the intended function. The program also includes periodic inspection and test of halon/carbon dioxide fire suppression systems. There are 21 implementing procedures that are scheduled on a regular basis that test these components. These tests have frequencies that vary between weekly to multi-year. The effectiveness review was comprised of a review of inspection implementation activities to date and pertinent issues in the Corrective Action Program, searching for identified age-related degradation of Fire Protection Systems. Pre-period of extended operation, visual inspection results, and resulting issues in the Corrective Action Program were also reviewed. The results of the review revealed that most of the fire protection issues/discrepancies are discovered during testing / inspection and or observation. The issues are entered into the Corrective Action Program and corrected through the work order process. There were no new or unexpected aging effects or inspection results revealed. There were also no major issues with the implementation of the Fire Protection aging management program. There was a Self-Assessment done for the entire Aging Management Program, which was BFN License Renewal Self-Assessment 2022. This assessment did not identify any deficiencies associated with the Fire Protection aging management program.

   This operating experience provides objective evidence that the Fire Barrier, Diesel-Driven Fire Pumps and Halon / Carbon Dioxide Fire Suppressions systems are effectively being monitored and tested to assure that these components will continue to perform their intended functions. Continued aging management of these components in accordance with the Fire Protection program assures that intended functions will be maintained during the subsequent period of extended operation.

2. In November 2016, during the performance of the Diesel Driven Fire Pump Functionality Test, the coolant reservoir began to leak at the coolant cap. There was noticeable corrosion and deterioration of the fill neck which prevented a strong seal. The fill neck and the reservoir is one component. This issue was entered into the Corrective Action Program, resulting in replacement of the coolant fill reservoir.

   This operating experience provides objective evidence that the Fire Protection program is effective to identify degraded conditions, and the Corrective Action Program is effective to correct them prior to loss of intended function.

3. In June 2019, during performance of the Surveillance Instruction for inspection of cable tray penetrations/covers and fire rated barriers by Fire Operations personnel, it was noted that several fire penetration barriers have additional penetrations through the fire barrier that were not identified in the Surveillance Instruction for inspection. There were seven conduits, one radio cable and one drain line not identified in the Surveillance Instruction. This issue was entered into the Corrective Action Program, resulting in an engineering evaluation which

determined that the additional penetrations should be added to the Surveillance Instruction. The Surveillance Instruction was subsequently revised to include the additional penetrations.

This operating experience provides objective evidence that when program deficiencies are identified in the Fire Protection program, the Corrective Action Program is utilized to correct the deficiencies to ensure that the Fire Protection program remains effective.

4. Based on NRC observations made during the BFN 2022 Triennial Fire Protection Inspection, it was identified that some electrical raceway fire barrier systems (ERFBS) are at higher risk of water damage than others. Consideration of this higher risk and BFN operating experience of damaged ERFBS identified outside the surveillance process warrants increasing the frequency for their inspection. A condition report was initiated to recommend a change in the frequency of inspection for these barriers. The eight conduits protected by ERFBS that were identified for higher risk of damage are six conduits at the Intake Pumping Station; one conduit in the Unit 2 Reactor Building and one conduit in the Unit 3 Reactor Building. The ERFBS associated with these conduits were being inspected on an 18 month interval. Based on the observations made and associated risk, the procedures for these inspections were revised from an 18 month inspection interval down to a six month inspection interval.

   This operating experience provides objective evidence that issues discovered through NRC observations during inspections are used to improve the overall performance so that the intended functions of fire barrier systems are maintained consistent with the current licensing basis during the subsequent period of extended operation.

<u>Conclusion</u>

The enhanced Fire Protection program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.16 Fire Water System

<u>Program Description</u>

The Fire Water System aging management program is an existing condition monitoring program that manages the loss of material and flow blockage in air indoor uncontrolled, air-outdoor, condensation, and raw water environments for water-based fire protection systems that consist of sprinklers, nozzles, fittings, valve bodies, fire pump casings, hydrants, hose stations, standpipes, aboveground and buried piping and piping components, tanks, strainers, and flow devices. Flow testing, visual inspections, and volumetric examinations are performed to ensure that loss of material due to general, pitting and crevice corrosion, microbiologically influenced corrosion, or fouling, and flow blockage due to fouling is adequately managed using the guidance of NFPA 25, 2011 Edition. When BFN operating experience has shown no loss of intended function of the in-scope SSC due to aging effects, testing and inspections will be conducted on a refueling outage interval as allowed by Revision of NUREG-2191, AMP XI.M27, Table XI.M27-1, Fire Water System Inspection and Testing Recommendations.

A review of BFN operating experience has revealed instances of recurring internal corrosion in the fire water system piping that is within the scope of the Fire Water System program. Inspections are performed on the fire water piping by non-intrusive volumetric examinations, to ensure that aging effects are managed, and that wall thickness is within acceptable limits.

Abnormal or unacceptable results are entered into the Corrective Action Program for review and resolution.

External surfaces of buried fire main piping are evaluated for loss of material and cracking with aging effects managed as described in the Buried and Underground Piping and Tanks program (B.2.1.27). The fire main buried cement lined pipe aging effects such as cracking are managed by the Internal Coating/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (B.2.1.28).

Sprinkler heads for each unit will be replaced or inspected. Either sprinklers are replaced before reaching 50 years inservice as applicable or a representative sample of sprinklers from one or more sample areas is tested by using the guidance of NFPA 25, 2011 Edition, “Inspection, Testing and Maintenance of Water-Based Fire Protection Systems.” Additionally, if sprinklers are not replaced, they shall be inspected prior to the end of the specified service life and at specified intervals thereafter in accordance with NFPA-25.

Portions of water-based fire protection system components that have been wetted but are normally dry, such as dry-pipe or preaction sprinkler system piping and valves, will be subjected to augmented testing and inspections beyond those of Revision 0 of NUREG-2191, Table XI.M27-1. The augmented tests and inspections will be conducted on piping segments that cannot be drained or piping segments that allow water to collect. Dry pre-action sprinkler systems are air filled, and trip tested dry.

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. The system flow testing, visual inspections and volumetric inspections assure that aging effects are managed such that the system intended functions are maintained. Flow testing results will be reviewed and trended to identify degrading trends prior to loss of system function. The program ensures that testing and inspection activities have been performed and documented. Abnormal results are entered into the Corrective Action Program for review and resolution.

Inspections and tests are performed by personnel qualified in accordance with station procedures and programs to perform the specified task. The inspections and tests follow station procedures that include inspection parameters for items such as lighting, distance, offset, presence of protective coatings, and cleaning processes.

The program will be enhanced, as noted below, to provide reasonable assurance that the Fire Water System aging effects will be adequately managed during the subsequent period of extended operation.

<u>NUREG-2191 Consistency</u>

The enhanced Fire Water System Program aging management program will be consistent with the 10 elements of aging management program XI.M27, Fire Water System, specified in NUREG-2191.

<u>Exceptions to NUREG-2191</u>

None.

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Revise implementing procedures to ensure that flushes are in accordance with NFPA 25, 2011 Edition, section 7.3.2.1, to mitigate or prevent fouling, which can cause flow blockage or loss of material, by clearing corrosion products and sediment.

   Program Element Affected: Element 2 - Preventative Actions

2. Revise implementing procedures to perform periodic flow tests, flushes, internal and external visual inspections, and testing of sprinklers systems.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

3. Revise implementing procedures to ensure that, when visual inspections are used to detect loss of material, the inspection technique will be capable of detecting surface irregularities that could indicate an unexpected level of degradation due to corrosion and corrosion product deposition. Where such irregularities are detected, follow-up volumetric wall thickness examinations will be performed. Additionally, volumetric wall thickness inspections will be conducted on portions of water-based fire protection system components that are periodically subjected to flow but are normally dry.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

4. Revise implementing procedures to ensure that visual examinations of cementitious materials will be conducted to detect indications of loss of material and cracking that could affect the system's ability to maintain pressure.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

5. Revise implementing procedures to meet guidelines of Revision 0 of NUREG-2191, Table XI.M27-1, Fire Water System Inspection and Testing Recommendations (NFPA 25, 2011 Edition, Guidelines).

   Program Element Affected: Element 4 - Detection of Aging Effects

6. Revise implementing procedures to ensure visual inspections are capable of evaluating: (i) the condition of the external surfaces of components, (ii) the conditions of the internal surfaces of components that could indicate wall loss or cracking, and (iii) the inner diameter of the piping as it applies to the design flow of the fire protection system (i.e., to verify that corrosion product buildup has not resulted in flow blockage due to fouling). Internal visual inspections used to detect loss of material are capable of detecting surface irregularities that could be indicative of an unexpected level of degradation due to corrosion and corrosion product deposition. Where such irregularities are detected, follow-up volumetric examinations will be performed.

   Program Element Affected: Element 4 - Detection of Aging Effects

7. Revise implementing procedures to ensure augmented tests and inspections are conducted on piping segments that cannot be drained or piping segments that allow water to collect:
   - In each 5-year interval, beginning 5 years prior to the subsequent period of extended operation, either conduct a flow test or flush sufficient to detect potential flow blockage, or conduct a visual inspection of 100 percent of the internal surface of piping segments that cannot be drained or piping segments that allow water to collect.
   - In each 5-year interval of the subsequent period of extended operation, 20 percent of the length of piping segments that cannot be drained or piping segments that allow water to collect is subject to volumetric wall thickness inspections. Measurement points are

obtained to the extent that each potential degraded condition can be identified (e.g., general corrosion, microbiologically influenced corrosion). The 20 percent of piping that is inspected in each 5-year interval is in different locations than previously inspected piping.

- If the results of a 100-percent internal visual inspection are acceptable, and the segment is not subsequently wetted, no further augmented tests or inspections are necessary.

For portions of the normally dry piping that are configured to drain (e.g., pipe slopes towards a drain point) the tests and inspections of Revision 0 of NUREG-2191, Table XI.M27-1 do not need to be augmented.

Program Element Affected: Element 4 - Detection of Aging Effects

8. Revise implementing procedures to require qualification for personnel conducting visual inspection in accordance with site procedures. The inspections and tests will follow site procedures that include inspection parameters for items such as lighting, distance, offset, presence of protective coatings, and cleaning processes.

Program Element Affected: Element 4 - Detection of Aging Effects

9. Revise implementing procedures to ensure that results of flow testing (e.g., buried and underground piping, fire mains, and sprinkler), flushes, and wall thickness measurements are monitored and trended. Degradation identified by flow testing, flushes, and inspections will be evaluated.

Program Element Affected: Element 5 - Monitoring and Trending

10. Revise implementing procedures to ensure that inspections with quantitative results, degradation identified will be projected until the next scheduled inspection. Results will be evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation. 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.

Program Element Affected: Element 5 - Monitoring and Trending

11. Revise implementing procedures to specify acceptance criteria for minimum design wall thickness, and for loose fouling products in systems that could cause flow blockage in the sprinklers or deluge nozzles.

Program Element Affected: Element 6 - Acceptance Criteria

12. Revise implementing procedures to ensure that if the presence of sufficient foreign organic or inorganic material to obstruct pipe or sprinklers is detected during pipe inspections, the material will be removed and the inspection results will be entered into the site's Corrective Action Program for further evaluation.

Program Element Affected: Element 7 - Corrective Actions

13. Revise implementing procedures to ensure that 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 acceptance criteria due to current or projected degradation (i.e., trending) additional tests will be conducted. The number of increased tests will be determined in accordance with the site's corrective action process; however, there will be no fewer than two additional tests for each test that did not meet acceptance criteria. The additional inspections will be completed within the interval (i.e., 5 years, annual) in which the original test was conducted. If subsequent tests do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of tests. At BFN, the additional tests will include at

least one test on one of the other units on site with the same material, environment, and aging effect combination.

Program Element Affected: Element 7 - Corrective Actions

14. Revise implementing procedures to ensure that an evaluation be conducted to determine if deposits need to be removed to determine if loss of material has occurred. When loose fouling products that could cause flow blockage in the sprinklers is detected, a flush will be conducted in accordance with the guidance in NFPA 25, 2011 Edition, Appendix D.5, “Flushing Procedures.” If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, inspection frequencies will be adjusted as determined by the site's Corrective Action Program.

Program Element Affected: Element 7 - Corrective Actions

Operating Experience

The following examples of operating experience provide objective evidence that the Fire Water System program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2022, a program effectiveness review was performed for the Fire Water System Program described in FSAR Section O.1.22 in support of preparing the BFN Subsequent License Renewal Application. The purpose of the program effectiveness review was to verify that the intent of the existing aging management program activities, to identify and correct, as warranted, age-related degradation of Fire Water Systems, is being effectively implemented in the initial license renewal period of extended operation. The activities include Diesel Driven and Electric Fire Pump inspections and tests; High Pressure Fire Protection flow test, flushes and valve cycling; Fire Hydrant inspections and flow tests; Fire Hose hydrostatic tests, flow tests and replacement; Biocide additions; logic tests, Local Fire Panel tests, Smoke and Heat detector tests as well as Spray and Sprinkler system tests, with documentation of findings, and follow-up actions in the Corrective Action Program. The Fire Water System program applies to water based fire protection systems and components that are tested in accordance with the applicable National Fire Protection Association codes and standards. There are 45 implementing procedures that are scheduled on a regular basis that test these components. The tests have frequencies that vary between weekly to multi-year. The program effectiveness review was comprised of a review of inspection implementation activities to date, searching for identified age-related degradation of fire water systems. Pre-period of extended operation, visual inspection results, and resulting issues in the Corrective Action Program were also reviewed. The review identified that age-related degradation of in-scope SSCs is identified and managed through the performance of surveillance test inspections, functional tests, and the Corrective Action Program. Age-related issues identified during the inspections were evaluated and corrected within the Corrective Action Program resulting in effective implementation of this aging management program.

   This operating experience provides objective evidence that the Fire Water Systems Program, which includes surveillance testing, piping inspections, maintenance practices, and Corrective Action Program, are managing aging effects for water-based fire protection systems such as fire pumps, distribution piping, sprinkler systems, deluge systems, and hose station standpipes to assure that these components will continue to perform their intended functions during the subsequent period of extended operation.

2. There was a Self-Assessment done for the entire Aging Management Program, which was BFN License Renewal Self-Assessment 2022. This assessment identified two deficiencies associated with the Fire Water Systems program. One deficiency was related to

testing / replacement of fast acting sprinklers, which NFPA 25 requires replacement or testing after 20 years service. This issue was initially addressed by stating that the original licensing commitment included all sprinkler types and that they would be replaced / tested at the 50 year interval. After further review, it was determined that BFN should follow the EPRI guidance for the testing / replacement and possible de-scoping of the sprinklers, and develop a project to complete this activity. This EPRI report may be used to support the service life assessment of the 50 year sprinklers as well as the fast acting sprinkler heads and development of a technical justification regarding the testing or replacement requirement. This project is scheduled to complete in February 2024. The other deficiency was related to the fire piping through wall leaks occurring over many years. A fire protection header piping replacement project has been ongoing since 2015. Approximately 1000 feet of header piping has been replaced in Unit 1, Unit 2, and Unit 3 Reactor Buildings through Fiscal Year 2020. The Turbine Building piping replacement for Unit 1, Unit 2, and Unit 3 is on-going and expected to continue through at least Fiscal Year 2025. Walkdowns continue throughout the facility to identify scope throughout to Fiscal Year 2027. The project has included replacement of isolation valves, where needed, which will allow the establishment of future clearances for maintenance. These projects will continue to resolve the fire protection piping issues.

This operating experience provides objective evidence that self-assessments are conducted and resolutions to discrepancies are addressed to ensure the Fire Water System components will continue to perform their intended functions during the subsequent period of extended operation.

3. During the review of NRC Information Notice 2013-006, “Corrosion in Fire Protection Piping Due to Air and Water Interaction,” it was determined that BFN had a sprinkler piping configuration that would prevent drainage of a portion of the piping in the Unit 1 Reactor Building. This issue was placed into the long term asset management program for a design change and funding. This issue did not get worked in an appropriate timeframe and a new condition report was generated to give this issue to a priority that will be properly evaluated and corrected as required. The walkdown for that condition report could not positively verify the actual section of piping with the drainage issue. However, during the search for the suspect piping, it was identified that there may be other potentially vulnerable sections of piping that have drainage issues. A separate condition report was generated for this issue to have a specialty contractor perform a review of the BFN Fire Protection System piping to ensure that any pipe slope issues will be identified and subsequently corrected. For those piping sections determined to not be sloped correctly for draining, interim actions will be put in place to either assist in draining or to monitor the conditions inside the piping sections, such as Ultrasonic Testing.

   This operating experience provides objective evidence that attention is being brought to long term issues that have not been corrected. This will help to ensure that fire water system components will continue to perform their intended functions during the subsequent period of extended operation.

4. System Engineering requested Fire Protection Engineering evaluate extending the frequency of the Electric Fire Pump Operability Test. This test was performed weekly, as required by Fire Protection Requirements Manual (FPRM) Surveillance Requirements. This issue was entered into the correction action program in April of 2022. As a result, an evaluation was performed to extend the electric fire pump test frequency. Fire Protection Engineering determined that extension of the electric fire pump surveillance frequency was justified in accordance with the EPRI guidance. The evaluation documented the data collected for past completed surveillances along with any failures, exhibited reliability, target reliability, and uncertainty. The exhibited reliability for electric fire pumps functionality is 100%. There were no documented

failures in the surveillance performances. The exhibited reliability was above the 98% target reliability value. This data provided the technical basis for extending the frequency from 7 days to 60 days. In addition to the surveillance data collected, the review of previous condition reports did not result in any information that contributed negatively towards the frequency extension. The associated FPRM requirement, as well as the Electric Fire Pump Operability Test procedure, were revised in August 2022 to change required testing frequency for the electric fire pumps to a frequency of once per 60 days.

This operating experience provides objective evidence that the Corrective Action Program is used to evaluate testing frequencies for optimization and to improve component reliability. This will help to ensure that fire water system components will continue to perform their intended functions during the subsequent period of extended operation.

Conclusion

The enhanced Fire Water System program will provide reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.17 Outdoor and Large Atmospheric Metallic Storage Tanks

Program Description

The Outdoor and Large Atmospheric Metallic Storage Tanks aging management program is an existing condition monitoring program that manages aging effects associated with in-scope outdoor aboveground tanks constructed on concrete or soil. BFN has no indoor, large volume tanks containing water designed with internal pressures approximating atmospheric pressure that are sited on concrete or soil, and no indoor tanks that sit on, or are embedded in concrete, where specific operating experience indicates that the tank surfaces are periodically exposed to moisture. The scope of this program includes the Unit 1 condensate storage tank, Unit 2 condensate storage tank, the Unit 3 condensate storage tank. These tanks contain treated water, are constructed of carbon steel, are not insulated, are coated both internally and externally as a preventive measure to mitigate corrosion. Each tank is supported on a foundation consisting of a fiber board on a concrete ring, under the perimeter of the tank bottom, which surrounds a bed of compacted sulfur free oiled sand. As such, the bottoms of the tanks are inaccessible for direct visual inspection.

The program manages loss of material by conducting periodic internal and external visual inspections on a frequency of 10 years or less in accordance with Table B.2.1.17. Cracking is not a predicted aging effect due to the carbon steel construction. Thickness measurements of tank bottoms are conducted to ensure that significant degradation is not occurring. Inspections and tests are performed by personnel qualified in accordance with site procedures and programs to perform the specified task. Volumetric inspections are within the scope of the American Society of Mechanical Engineers Boiler and Pressure Vessel (ASME) Code and will follow procedures consistent with the ASME Code. All other inspections and testing are to follow site procedures that include inspection parameters for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. The periodic inspection results are compared to acceptance criteria and include trending to allow corrective action to be taken prior to loss of intended function.

<table>
<tr><th colspan="5">Table B.2.1.17-1, Tank Inspection Recommendations[2]</th></tr>
<tr><th colspan="5">Inspections to Identify Degradation of Inside Surfaces of Tank Shell, Roof[4], and Bottom[5,]</th></tr>
<tr><th>Material</th><th>Environment</th><th>Aging Effect Requiring Management (AERM)</th><th>Inspection Technique[3]</th><th>Inspection Frequency</th></tr>
<tr><td rowspan="2">Steel</td><td>Air, condensation</td><td>Loss of material</td><td rowspan="2">Visual from inside surface or Volumetric from outside surface[7]</td><td>Each 10-year period starting within10 years before the subsequent period of extended operation</td></tr>
<tr><td>Treated water</td><td>Loss of material</td><td>One-time inspection conducted in accordance with the One-Time Inspection program (B.2.1.20) [8]</td></tr>
<tr><th colspan="5">Inspections to Identify Degradation of External Surfaces of Tank Shell, Roof, and Bottom</th></tr>
<tr><th>Material</th><th>Environment</th><th>Aging Effect Requiring Management (AERM)</th><th>Inspection Technique[3]</th><th>Inspection Frequency</th></tr>
<tr><td rowspan="2">Steel</td><td>Air – indoor uncontrolled

Air – outdoor</td><td>Loss of material</td><td>Visual from outside surface</td><td>Each refueling outage interval</td></tr>
<tr><td>Soil, concrete</td><td>Loss of material</td><td>Volumetric from inside surface</td><td>Each 10-year period starting within 10 years before the subsequent period of extended operation</td></tr>
</table>

<u>Notes</u>

1. Not used.
2. When one-time internal inspections in accordance with these footnotes are used in lieu of periodic inspections, the one-time inspection must occur within the 5-year period before the start of the subsequent period of extended operation.
3. Alternative inspection methods may be used to inspect both surfaces (i.e., internal, external) or the opposite surface (e.g., inspecting the internal surfaces for loss of material from the external surface) as long as the method has been demonstrated to be effective at detecting the AERM and a sufficient amount of the surface is inspected to provide reasonable assurance that localized aging effects are detected.
4. Nonwetted surfaces on the inside of a tank (e.g., roof, surfaces above the normal waterline) are inspected in the same manner as the wetted surfaces based on the material, environment, and AERM.
5. Visual inspections to identify degradation of the inside surfaces of tank shell, roof, and bottom cover all the inside surfaces.
6. Not applicable to BFN due to treated water stored in the condensate storage tanks.
7. At least 20 percent of the tank's internal surface is to be inspected using a method capable of precisely determining wall thickness. The ultrasonic examination inspection method will be used and is an effective method capable of detecting both general and pitting corrosion.
8. At least one tank for each material and environment combination is inspected. The tank inspection can be credited towards the sample population for the One-Time Inspection program (B.2.1.20).

NUREG-2191 Consistency

The enhanced Outdoor and Large Atmospheric Metallic Storage Tanks aging management program will be consistent with the 10 elements of aging management program XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, specified in NUREG-2191, with the following exception.

Exceptions to NUREG-2191

The guidance of the GALL-SLR to apply sealant or caulking at the interface between the tank external surface and concrete or earthen surface will not be used as there is no interface between the tank external surface and concrete or earthen surface at BFN for the condensate storage tanks. BFN takes exception to applying sealant or caulking at the interface between the tank external surface and concrete or earthen surface. **Program Elements Affected: Preventive Actions (Element 2); Detection of Aging Effects (Element 4); Acceptance Criteria (Element 6); and Corrective Actions (Element 7)**

Justification for Exception

The configuration of the BFN condensate storage tanks is such that there is no interface between the tank external surface and concrete or earthen surface due to the fiber board on top of the concrete ring of the foundation of the tanks. The fiber board helps mitigate corrosion of the tank by minimizing the amount of water and moisture penetrating the interface (i.e., the fiber board itself). Therefore, there is no need for sealant or caulking.

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Revise implementing procedures to require volumetric inspections of the tank bottoms whenever the tank is drained, or at intervals in accordance with Table B.2.1.17-1, "Tank Inspection Recommendations," to determine potential loss of material of tank bottoms. Table B.2.1.17-1 and the associated table notes will be added to the applicable procedure(s). The periodic inspections of the interior and bottom of the condensate storage tanks will manage the effects of corrosion on the intended function of these tanks.

   Program Element Affected: Element 4 - Detection of Aging Effects

2. Revise implementing procedures to require periodic visual inspections of tank exterior metallic surfaces to detect degradation at each outage, every two years, to confirm that paint and coatings are intact.

   Program Element Affected: Element 4 - Detection of Aging Effects

3. Revise implementing procedures to require volumetric inspections of the tank bottoms whenever the tank is drained, or at intervals in accordance with Table B.2.1.17-1, "Tank Inspection Recommendations," to determine potential loss of material of tank bottoms.Table B.2.1.17-1 and the associated table notes will be added to the applicable procedure(s).

   Program Element Affected: Element 4 - Detection of Aging Effects

4. Revise implementing procedures to note when inspections are conducted on a sampling basis, subsequent inspections are conducted in different locations unless the program states the basis for why repeated inspections will be conducted in the same location.

   Program Element Affected: Element 4 - Detection of Aging Effects

5. Revise implementing procedures to ensure volumetric inspections will be consistent with the American Society of Mechanical Engineers (ASME) code. All other inspections and testing are to follow site procedures that include inspection parameters for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

   Program Element Affected: Element 4 - Detection of Aging Effects

6. Revise implementing procedures to require identified degradation, where practical, to be projected until the next scheduled inspection.

   Program Element Affected: Element 5 - Monitoring and Trending

7. Revise implementing procedures to require results to be evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation.

   Program Element Affected: Element 5 - Monitoring and Trending

8. Revise implementing procedures to require additional inspections to be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending). The number of increased inspections is determined in accordance with the site's corrective action process; however:
   - For inspections where only one tank of a material, environment, and aging effect was inspected, all tanks in that grouping will be inspected.
   - For other sampling based inspections (e.g., 20 percent, 25 locations) the smaller of five additional inspections or 20 percent of the inspection population is conducted. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause is conducted to determine the further extent of inspection. The additional inspections include inspections at all of the units with the same material, environment, and aging effect combination.
   - The timing of the additional inspections is based on the severity of the degradation identified and is commensurate with the potential for loss of intended function. However, except for external visual inspections, the additional inspections are completed within the interval in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the 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. External visual inspections are conducted within the original refueling outage interval.
   - If any projected inspection results do not meet the acceptance criteria prior to the next scheduled inspection, inspection frequencies are adjusted as determined by the site's Corrective Action Program. However, for one time inspections that do not meet the acceptance criteria, inspections are subsequently conducted at least at 10 year inspection intervals.

   Program Element Affected: Element 7 - Corrective Actions

<u>Operating Experience</u>

The following examples of operating experience provide objective evidence that the Outdoor and Large Atmospheric Metallic Storage Tanks program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation:

1. In 2022, a program effectiveness review was performed for the Aboveground Carbon Steel Tanks Program described in FSAR Section O.1.23. The purpose of the program effectiveness

review was to verify that the existing aging management program activities, to identify and correct, as warranted, age-related degradation of components monitored by the Inspections of the Aboveground Carbon Steel Tanks Program, are being effectively implemented in the initial license renewal period of extended operation. The program effectiveness review was comprised of a review of inspection implementation activities to date and pertinent issues in the Corrective Action Program, searching for identified age-related degradation of components related to Aboveground Carbon Steel Tanks. The BFN Aboveground Carbon Steel Tanks Program manages the effects of aging on the internal and external surfaces of the condensate storage tanks. that are within the scope of 10 CFR 54.4, Requirements for Renewal of Operating License for Nuclear Power Plants. The Above Ground Carbon Steel Tanks Program initial inspections were completed prior to the period of extended operation. These Ultrasonic Test (UT) inspections were completed in 2011 and 2012. The UT Inspections were again conducted during the period of 2013 through 2017. The completion date of these inspections was July 17, 2017. The initial pre-period of extended operation inspections identified that the Unit 1 and Unit 3 condensate storage tank inspections identified a few floor plate thickness issues, with some locations being below the nominal thickness of 0.25 inches, the minimum readings being 0.21 inches. This was documented in the Corrective Action Program, resulting in an engineering evaluation that found the Unit 1 and Unit 3 readings to be acceptable for continued use during the period of extended operation and documented the data as baseline data for trending after future planned inspections which are conducted every 5 years.

This operating experience provides objective evidence that maintenance practices and the corrective action program effectively monitor and maintain the condition of the condensate storage tanks to assure that these components will be able to continue to perform their intended functions during the subsequent period of extended operation.

2. The condensate storage tanks were externally visually inspected during the period of extended operation on July 17, 2017, and on May 24, 2022. These external inspections inspected for cracks, staining, and deteriorated penetration of the tanks as well as supporting concrete structures, miscellaneous steel supports, and electrical components. The results for the Unit 1, 2, and 3 tanks were acceptable. The condensate storage tanks were internally inspected during the period of extended operation. The Unit 1 condensate storage tank was inspected during November 2018. The Unit 2 condensate storage tank was inspected during April 2019. The Unit 3 condensate storage tank was inspected during March 2020. These internal inspections verified that protective coatings are adhered to the surface and have no indications of delamination, peeling, cracking, flaking, discoloration, or blistering. The Work Orders that performed the condensate storage tank inspections also documented that UT examinations were conducted. However, the UT results are not documented as part of the Work Order package. This issue has been entered into the Corrective Action Program. This has resulted in action which found the UT results to be acceptable and documented this in the Condition Report.

   This operating experience provides objective evidence that maintenance practices and the Corrective Action Program effectively monitor and maintain the condition of the condensate storage tanks to assure that these components will be able to continue to perform their intended functions during the subsequent period of extended operation.

3. The March 2013 review of external Operating Experience item OE36492, Leak identified in Refueling Water Storage Tank Base Weld, is documented in the Corrective Action Program. The review determined that the BFN condensate storage tanks could have similar issues and resulted in actions to perform internal UT inspections of the bottom or floor of the Units 1, 2, and 3 condensate storage tanks. The inspection results were reviewed by engineering and

determined to be acceptable. These results were entered into the Corrective Action Program. The corrective actions included requirements for trending of the locations determined to be below the nominal wall thickness value. All condensate storage tank inspection results were evaluated as being acceptable for continued operation having both structural and leak integrity.

This example demonstrates that external operating experience related to the Above Ground Carbon Steel Tanks aging management program has been used to identify and correct program elements to assure that these components will be able to continue to perform their intended functions during the subsequent period of extended operation.

4. The Browns Ferry Nuclear 2020 License Renewal Self-Assessment was conducted and documented in the corrective action. The purpose of the Self-Assessment was to review License Renewal commitments and inspection documents during the period of extended operation. This assessment identified no issues associated with the Aboveground Carbon Steel Tanks Program.

   This example demonstrates that periodic self-assessments of the Above Ground Carbon Steel Tanks aging management program have been performed to identify and correct program elements to assure that these components will be able to continue to perform their intended functions during the subsequent period of extended operation.

Conclusion

The enhanced Outdoor and Large Atmospheric Metallic Storage Tanks program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.18 Fuel Oil Chemistry

Program Description

The Fuel Oil Chemistry aging management program is an existing mitigative and condition monitoring program that includes activities which provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of license renewal. The Fuel Oil Chemistry program manages loss of material in aluminum, copper alloy, nickel alloy, steel, and stainless steel piping, piping components, and tanks with a fuel oil environment. Fuel oil sampling and analysis is performed in accordance with approved procedures for new fuel oil and stored fuel oil. Fuel oil quality is maintained by monitoring and controlling fuel oil contaminants in accordance with the Technical Specifications, Technical Requirements Manual, and ASTM guidelines. Fuel oil analyses that do not meet acceptance criteria are evaluated in accordance with the Corrective Action Program. If analysis of fuel oil indicates biological activity or evidence of corrosion then the need for biocide or corrosion inhibitor addition is evaluated.

The fuel oil tanks within the scope of license renewal are uncoated. Fuel oil tanks are periodically drained of accumulated water and sediment, cleaned, and accessible tanks are internally inspected. At least once during the 10-year period prior to the subsequent period of extended operation the internal surfaces of accessible fuel oil tanks are visually inspected and the tank bottoms are volumetrically inspected. During the subsequent period of extended operation, the accessible tanks are visually inspected and the accessible tank bottoms are volumetrically inspected at least once every 10 years. Degradation of tank internal surfaces that does not meet acceptance criteria is evaluated in accordance with the Corrective Action Program. Tank inspection results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation. These activities effectively manage the effects of aging by identifying age-related degradation and maintaining potentially harmful contaminants at low concentrations.

Fuel Oil system components constructed of steel are exempt from One-Time Inspection because these system components meet the criteria for excluding these one-time inspections. Inspections will be performed as described in the One-time Inspections program (B.2.1.20) on Fuel Oil system components constructed of materials other than steel prior to the subsequent period of extended operation.

NUREG-2191 Consistency

The Fuel Oil Chemistry aging management program will be consistent with the 10 elements of aging management program XI.M30, Fuel Oil Chemistry, specified in NUREG-2191, with the following exception.

Exceptions to NUREG-2191

Ultrasonic thickness measurements of the Diesel Generator Day Tanks bottom surfaces will not be obtained because the Diesel Generator Day Tanks bottoms are not accessible to perform ultrasonic thickness measurements of the tank bottoms. **Program Element Affected: Detection of Aging Effects (Element 4)**

Justification for Exception

The size and design of the Diesel Generator Day Tanks do not allow access for internal inspection and also prevents access to the tanks bottom external surface such that external tanks bottom thickness measurements cannot be obtained. However, the contents sampling frequency of these Diesel Generator Day Tanks, which is once every 31 days or when the Emergency Diesel Generator is operated for more than one hour, whichever occurs first, ensures that water will be detected early following its introduction into the tanks, thereby minimizing both the quantity of water collected in the tanks, and the length of contact time prior to its discovery. Thus, this frequent content sampling and corrective actions, if and when necessary, serve to prevent water accumulation and tanks internal surface degradation in lieu of tanks bottom thickness measurement checks which cannot be performed due to the tanks design and construction.

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Revise implementing procedures to require, for each Diesel Generator 7-Day Fuel Oil Tank and the Diesel Driven Fire Pump Fuel Oil Tank bottom surfaces, that UT inspections be performed at least once prior to the subsequent period of extended operation, at least once every 10 years during the subsequent period of operation, and if degradation is identified, UT

examination of the tanks bottoms will be performed, the results analyzed and corrective actions taken, if necessary, to ensure integrity until the next scheduled inspection.

Program Element Affected: Element 4 - Detection of Aging Effects

2. Revise implementing procedures to require, prior to the subsequent period of extended operation, performance of a one-time inspection of system components, exposed to diesel fuel oil, constructed of materials other than the steel in accordance with the BFN One-Time Inspection program (B.2.1.20).

   Program Element Affected: Element 4 - Detection of Aging Effects

3. Revise implementing procedures to require that results of inspections be trended to provide for timely detection of aging effects and, where practical, require that identified degradation be projected until the next inspection.

   Program Element Affected: Element 5 - Monitoring and Trending

4. Revise implementing procedures to require that thickness measurements of each Diesel Generator 7-Day Fuel Oil Tank and the Diesel Driven Fire Pump Fuel Oil Tank bottom surfaces are evaluated against the design thickness and corrosion allowance.

   Program Element Affected: Element 6 - Acceptance Criteria

5. Revise implementing procedures to require that corrective actions are taken to prevent recurrence when the specified limits for fuel oil standards are exceeded or when water is drained during periodic surveillance. If accumulated water is found in a fuel oil storage tank, it is immediately removed. In addition, when the presence of biological activity is confirmed, or if there is evidence of MIC, a biocide, in the form of a multi-function diesel fuel oil inhibitor may be added to fuel oil, or the fuel oil replaced.

   Program Element Affected: Element 7 - Corrective Actions

Operating Experience

The following examples of operating experience provide objective evidence that the Fuel Oil Chemistry program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for Fuel Oil Chemistry Program described in FSAR Section O.1.24 in support of preparing the BFN Subsequent License Renewal Application. The purpose of the program effectiveness review was to verify that the management of fuel oil chemistry provides monitoring and inspection to detect water, sediment, and particulate contamination, thereby managing the conditions that cause general, pitting and microbiologically influenced corrosion (MIC) of the diesel fuel tank internal surfaces during the initial license renewal period of extended operation. This is an existing aging management program for BFN Units 1, 2 and 3. The program effectiveness review was comprised of a review of fuel oil testing results, diesel generator 7-day tank inspection reports, and any Condition Reports (CRs) entered into the Corrective Action Program. Operating experience within the Corrective Action Program relative to fuel oil quality activities from 2010 through 2022 was reviewed. The review determined that the sampling and analysis of new and stored fuel oil, removal of water from tank bottoms, and tank internal inspections are effective in identifying detrimental impurities in fuel oil and age-related degradation in storage tank bottoms. Deficiencies identified during the performance of periodic aging management program activities were evaluated in the Corrective Action Program. The sampling and analysis of new and stored fuel oil, removal of water from tank bottoms, and tank internal

inspections, along with the evaluation of deficiencies within the Corrective Action Program, have resulted in the effective implementation of these aging management programs.

This operating experience provides objective evidence that existing aging management program activities are being effectively implemented to manage aging effects associated with a fuel oil environment, and that deficiencies identified during the implementation of the program are entered into the Corrective Action Program for evaluation. Continued implementation of the program will assure that components exposed to fuel oil within the scope of the program will continue to perform their intended functions during the subsequent period of extended operation.

2. Fuel oil is sampled and tested for its chemical qualities quarterly for the Emergency Diesel Generators and the diesel driven fire pump. The Emergency Diesel Generators’ 7-day tanks are sampled monthly for detection of water. A review of a sample of completed tests from 2010 through 2022 have identified no failed chemistry specifications for the fuel oil. A review of the Corrective Action Program was performed to identify issues with water in fuel oil tanks during the same period. Two CRs were identified where water was detected, and no CRs were identified documenting deficiencies in fuel oil chemistry parameters. Water was detected once in the diesel fire pump fuel oil tank, and once in the 3A Emergency Diesel Generators’ 7-day fuel oil tank. All water was removed in both cases, and follow-up sampling was conducted to verify no additional water accumulated.

   This operating experience provides objective evidence that routine periodic surveillance is effective at identifying the presence of contaminants that promote aging effects and that fuel oil analyses that do not meet acceptance criteria are entered into the Corrective Action Program for evaluation and the identification of corrective actions.

3. The Emergency Diesel Generators’ 7-day fuel oil tanks are cleaned and inspected every 10 years. A report is developed documenting the condition of the tanks following each inspection. All tanks were cleaned and inspected between 2019 and 2020. A review of the tank inspection reports show that the tanks are in good condition, essentially unchanged from initial installation. Several examples of minor indications from manufacturing and installation were documented. The tank thicknesses were measured with little to no change from the previous inspections. Some indications were documented for follow-up inspection during the next inspection.

   This operating experience provides objective evidence that fuel oil tank inspection activities are effective in identifying degraded conditions caused by aging effects, and the Corrective Action Program is effective in evaluating the conditions to determine their impacts to system intended functions.

4. External operating experience related to defects in diesel fuel oil tanks at Oconee in August on 2012 was reviewed for applicability at BFN. The issue was reviewed against the BFN program and procedures and determined that the BFN program was adequate to address the identified issue and no changes in the program were required. The operating experience was shared with the chemistry section in a crew training session. This operating experience review was documented in the Corrective Action Program.

   This operating experience provide objective evidence that the program is informed and enhanced, when necessary, through the systematic and ongoing review of industry operating experience. Therefore, there is confidence that implementation of the Fuel Oil Chemistry program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

5. The BFN Quality Assurance (QA) organization performed audits of the Fuel Oil Chemistry Program. These audits are documented in QA audit reports in 2010, 2011, and 2015. In 2015,

it was identified that some testing procedures for diesel fuel oil require testing for gross calorific value, however, this testing requirement is missing in the Diesel Fuel Oil Testing and Monitoring Program procedure. This issue was entered into the Corrective Action Program documenting, which recommended adding gross calorific testing to Diesel Fuel Oil Testing and Monitoring Program procedure. As a result, the procedure was revised to add this requirement. An administrative deficiency was identified in the 2010 QA audit report and entered into the Corrective Action Program. No deficiencies were identified in the 2011 QA audit report.

This operating experience provide objective evidence that the program is informed and enhanced, when necessary, through the systematic and ongoing review of plant-specific operating experience. Therefore, there is confidence that implementation of the Fuel Oil Chemistry program will effectively manage the effects of aging and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced Fuel Oil Chemistry program will provide reasonable assurance that the loss of material aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.19 Reactor Vessel Material Surveillance

Program Description

The BFN Reactor Vessel Material Surveillance aging management program is an existing condition monitoring program that manages the loss of fracture toughness due to neutron embrittlement of the ferritic reactor vessel beltline materials in a reactor coolant and neutron flux environment. The program utilizes surveillance capsules that are located near the inside wall of the reactor vessel beltline region to duplicate the neutron spectrum, temperature history, and neutron fluence of the reactor vessel inner surface. The resulting lead factor allows the surveillance capsules to achieve a neutron fluence exposure earlier than the reactor vessel allowing the surveillance capsules to be withdrawn and tested prior to the reactor vessel reaching the neutron fluence of interest.

The BFN Reactor Vessel Material Surveillance program meets the requirements of 10 CFR Part 50, Appendix H, via Browns Ferry's participation in the Boiling Water Reactor Vessel and Internals Project (BWRVIP) Integrated Surveillance Program (ISP) in lieu of a plant-specific capsule removal and testing schedule. For the subsequent period of extended operation, the program will implement BWRVIP-321 Revision 1-A, “Boiling Water Reactor Vessel and Internals Project, Plan for Extension of the BWR Integrated Surveillance (ISP) Through the Second License Renewal (SLR),” to maintain compliance with the requirements of 10 CFR Part 50, Appendix H.

The program provides sufficient material data and dosimetry to: (a) monitor irradiation embrittlement neutron fluences greater than the projected neutron fluence at the end of the subsequent period of extended operation, and (b) provide adequate dosimetry monitoring during the operational period.

The program is a condition monitoring program that measures the increase in Charpy V-notch 30 foot-pound (ft-lb) transition temperature and the drop in upper-shelf energy as a function of neutron fluence and irradiation temperature. reactor vessel beltline material test results provide reactor vessel material fracture toughness data for the neutron irradiation embrittlement time-limited aging analyses (TLAAs) (e.g., upper-shelf energy and pressure-temperature limits evaluations). The reactor vessel beltline material surveillance capsules are removed at various exposure intervals for monitoring and trending purposes.

Surveillance capsules are withdrawn, tested, and results reported in accordance with 10 CFR Part 50, Appendix H, and ASTM E 185-82. Any changes to the surveillance capsule withdrawal schedule, including changing the status of standby capsule, must be approved by the NRC prior to implementation per 10 CFR Part 50, Appendix H. Specimens from tested capsules and withdrawn untested capsules are maintained in storage for possible reconstitution or reinsertion. Abnormal or unexpected results are entered into the Corrective Action Program for engineering evaluation.

For BFN Units 1, 2, and 3, ISP implementation and the surveillance specimen schedule for withdrawal and testing for the original 40 year operating license and the License Renewal period of extended operation is governed and controlled by BWRVIP-86 Revision 1-A, the BWRVIP responses to NRC Requests for Additional Information dated May 30, 2001, and December 22, 2001, and the NRC Safety Evaluation dated February 1, 2002 (Note: BWRVIP-86, Revision 1-A was approved by the NRC and issued in October 2012, superseding both BWRVIP-86-A and BWRVIP-116). Two BFN Unit 2 test specimen surveillance capsules have previously been withdrawn and tested as part of the original plant-specific capsule removal and testing schedule and the ISP. An additional BFN Unit 2 test specimen surveillance capsule is scheduled for withdrawal during the License Renewal period of extended operation. This capsule is the third set of Unit 2 test specimens, located at Azimuth 300°, which are currently scheduled for removal in the refueling outage closest to, but without exceeding, 40 EFPY of operation.

For the SLR subsequent period of extended operation, the ISP will be extended through the subsequent period extended operation in accordance with BWRVIP-321 Revision 1-A, “Boiling Water Reactor Vessel and Internals Project Plan for Extension of the BWR Integrated Surveillance Program (ISP) Through the Second License Renewal (SLR),” which has been reviewed and approved by the NRC.

The plan established in BWRVIP-321 Revision 1-A not only satisfies the requirements of 10 CFR 50 Appendix H, for an ISP through the subsequent period extended operation, it also meets NRC expectations for an ISP in the subsequent period of extended operation as stated in NUREG-2191, “Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report.” The plan calls for installation of a single Supplemental SLR (SSLR) capsule holder in a host plant (subsequently chosen by the BWRVIP) to obtain the needed catch-up fluence to support 80 years of operation for the U.S. fleet. The single SSLR capsule holder will contain three capsules which correspond to 3 capsule groupings (Groups 1, 2, and 3) that are defined in BWRVIP-321 Revision 1-A based on the amount of catch-up fluence needed for the ISP representative material specimens to attain a neutron fluence that meets or exceeds (by up to a factor of 2) the target reactor vessel fluence for 80 years of operation, within a reasonably short time frame. Group 1 requires the lowest amount of catch-up fluence, while Group 3 requires the largest amount of catch-up fluence. The ISP representative material specimens for BFN are assigned to either Group 1 or Group 2.

The approach that the BWRVIP ISP is using to expand the program for the subsequent period extended operation, is to ensure that all ISP representative materials have specimens that are irradiated to a fluence that bounds the SLR fluences of all target materials represented by that surveillance material. This will be accomplished by irradiating, reconstituting, and testing previously tested ISP capsule materials as necessary to ensure that any plant which pursues SLR will have appropriate data available for its representative materials. When all remaining capsules are tested under the ISP for the License Renewal period of extended operation, the current set of representative material specimens will have been fully used, with the exception of potential existing reconstituted capsules. For materials which require additional surveillance data, previously tested specimens from the BWRVIP ISP repository will be used for reconstitution. New Charpy test specimens will be fabricated by machining an insert, or central portion of the test specimen, from the broken Charpy halves and welding end tabs to the insert. Prior to reconstitution, the specimen inserts will be placed into specially designed SSLR capsules and be reinserted into the BWRVIP selected host plant to continue to irradiate the specimens to accumulate sufficient fluence to meet or exceed 80-year projected reactor vessel fluences. After irradiation is complete, reconstituted specimens will be fabricated and tested only for those materials that are needed by BWRs pursuing SLR, including BFN.

Presently, there are no plans in the ISP to withdrawal any material surveillance capsules from either Unit 1 or Unit 3, as the BFN Unit 2 capsules provide the best representative plate material for all three units and the best representative weld material for Units 2 and 3. The best representative weld material for Unit 1 was found in capsules pulled from other plants as part of the BWR Owners' Group Supplemental Surveillance Program. Although the surveillance capsules for Units 1 and 3 will be deferred and not tested as part of the ISP, these capsules that were previously credited as part of BFN plant-specific surveillance programs will continue to be irradiated in their host reactors.

The reserved surveillance capsules from BFN Units 1 and 3, represent reactor vessel material surveillance resources that could be employed to support further license extensions. BFN is committed to the BWRVIP ISP program and will support the program through additional capsule withdrawals as deemed appropriate by the BWRVIP and NRC. While not expected, if the reactor vessel exposure conditions (neutron flux, spectrum, irradiation temperature, etc.) are altered, then the basis for the projection of neutron fluence to the end of the subsequent period of extended operation will be reviewed and, if required, modifications will be made to the Reactor Vessel Material Surveillance program.

BFN Units 1, 2, and 3 are projected to achieve 50 EFPY, 64 EFPY, and 62 EFPY of operation, respectively, at the end of the subsequent period extended operation. BFN has performed the validation required by Section 9.2 of BWRVIP-321, Revision 1-A, based on SLR fluence projections to the end of the subsequent period extended operation and has determined that additional surveillance data from the ISP supplemental SLR (SSLR) capsule materials will not be needed to bound the BFN SLR fluence needs for 80 years. However, due to inherent uncertainties in these fluence projections, BFN will enhance the Reactor Vessel Material Surveillance aging management program by incorporating the requirements of BWRVIP-321 Revision 1-A to maintain compliance with 10 CFR 50, Appendix H.

NUREG-2191 Consistency

The enhanced Reactor Vessel Material Surveillance aging management program will be consistent with the 10 elements of aging management program XI.M31, Reactor Vessel Material Surveillance, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Implement BWRVIP-321 Revision 1-A to maintain compliance with 10 CFR 50 Appendix H during the subsequent period of extended operation.

   Program Elements Affected: Element 1 - Scope of Program, Element 3 - Parameters Monitored or Inspected, Element 4 - Detection of Aging Effects, and Element 5 - Monitoring and Trending

Operating Experience

The following examples of operating experience provide objective evidence that the Reactor Vessel Surveillance program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for the Reactor Vessel Surveillance program described in FSAR Section O.1.25. The purpose of the program effectiveness review was to verify that the existing aging management program activities, which are to complete surveillance capsule testing and valuation, prepare for withdrawal of the next scheduled capsules, and document program updates is being effectively implemented during the first period of extended operation. The program effectiveness review was comprised of a review of inspection implementation activities to date and pertinent issues in the Corrective Action Program, searching for identified age-related degradation of components related to the Reactor Vessel Surveillance program. The review determined that the Reactor Vessel Surveillance program is being implemented as described in FSAR Section O.1.25 during the first period of extended operation. Administrative issues associated with the management of the program were identified and entered into the Corrective Action Program.

   This example provides objective evidence of aging management program effectiveness during the initial period of extended operation and provides objective evidence that the continued implementation of the Reactor Vessel Surveillance aging management program will effectively manage aging by identifying degradation prior to failure or loss of intended function during the subsequent period of extended operation.

2. Since 2002, BFN has been a part of the Boiling Water Reactor Vessel and Internals Project (BWRVIP) Integrated Surveillance Program (ISP). BFN enhanced the inspection program to include requirements of then proposed BWRVIP-116. BFN subsequently included Unit 1 into the BWRVIP ISP. The inspection history and the planned future reactor vessel surveillance program inspections are as follows; The first set of test specimens for Unit 2 was removed and tested at approximately 8.0 Effective Full Power Years (EFPY) of operation as part of the BFN plant-specific surveillance program. The capsule removed was located at Azimuth 30 degrees and was removed during Unit 2 Refueling Outage 7 (U2R7) in 1994. This capsule was reinstalled with reconstituted specimens during Unit 2 Refueling Outage 8 (U2R8) in 1996. BFN is now implementing the BWRVIP ISP in lieu of the plant-specific program. The current BFN reactor vessel surveillance program follows the industry guidance of BWRVIP-86 Revision 1-A. Note BWRVIP-86, Revision 1-A was approved by the NRC and issued in October 2012, superseding both BWRVIP-86-A and BWRVIP-116. A test specimen surveillance capsule, the second set of Unit 2 test specimens located at Azimuth 120 degrees,

was withdrawn in accordance with the ISP in 2011 during Unit 2 Refueling Outage 16 (U2R16) at approximately 23 EFPY of operation. An additional test specimen surveillance capsule is scheduled for withdrawal during the license renewal period, this being the third set of Unit 2 test specimens located at Azimuth 300 degrees, which are currently scheduled for removal in the refueling outage closest to without exceeding 40 EFPY of operation. At the present time, this would correspond to Unit 2 Refueling Outage 25 (U2R25) in 2029. Presently, there are no plans to withdrawal any capsules from either Unit 1 or Unit 3, as the BFN Unit 2 capsules provide the best representative plate material for all three units and the best representative weld material for Units 2 and 3 (the best representative weld material for Unit 1 was found in capsules pulled from other plants as part of the BWR Owners Group Supplemental Surveillance Program). Although the surveillance capsules for Units 1 and 3 will be deferred and not tested as part of the ISP, these capsules that were previously credited as part of BFN plant-specific surveillance programs will continue to be irradiated in their host reactors. Therefore, all irradiated material samples for Units 1 and 3 continue to remain available to the ISP, as needed, and no overall reduction in the number of materials being irradiated, number of specimen types, or number of specimens per reactor occurs as a result of the ISP. Test results will provide the necessary data to monitor embrittlement for Units 1, 2, and 3. Since the predicted adjusted reference temperature of the reactor vessel beltline steel is less than 100 degrees F at end-of-life, the use of the capsules per the ISP satisfy the requirements of 10 CFR 50, Appendix H, and ASTM E185-82. Revisions to fluence calculations using data obtained from the surveillance capsule specimens will use an NRC approved methodology that satisfies Regulatory Guide 1.190. As a result, it is concluded that the requirements of the Reactor Vessel Surveillance program are being met.

These examples demonstrates that the industry guidelines delineate in BWRVIP-86-A continue to be effectively implemented to monitor the loss of fracture toughness of the reactor vessel beltline materials due to neutron irradiation embrittlement within the scope of the Reactor Vessel Surveillance aging management program.

3. There have been a some issues related to the Reactor Vessel Surveillance program from internal and external operating experience events that have been entered in the Corrective Action Program. Some of these issues are as follows.
    - In April 2015, during the Sequoyah Nuclear Plant Unit 1 end of cycle 20 refueling outage, unanticipated damage to the 'S' and 'W' surveillance capsules was identified. Inspections determined that the surveillance capsules were not contained within the intact designated baskets. An extensive foreign object search and recovery initiative was conducted. The condition was determined to be caused by the use of an inadequate procedure used to perform surveillance capsule relocations during the previous refueling outage. The BFN review of this event was conducted in accordance with the Corrective Action Program which resulted in a revision which incorporated learnings from the event into BFN aging management program implementing procedures.
    - During the BFN Unit 2 Refueling Outage 20 (spring 2019) internal vessel visual inspection of the Reactor Vessel Surveillance Capsule Holder at 30 degrees, a loss of material was noted on the metal within the capsule basket for the Surveillance Capsule Holder. Additional examination of the inspection results verified that one of the tensile specimen tubes in the specimen holder had failed, creating a hole in the tube. This resulted in several actions. However, since the surveillance capsule at 30 degrees was a spare, there was no impact to the present aging management program. This issue was entered into the Corrective Action Program. Action to evaluate the loss of this surveillance capsule on the ability to perform the Reactor Vessel Material program during

the SLR period of extended operation was completed which shows that there will be no impact.

This example demonstrates that internal and external operating experience related to the Reactor Vessel Surveillance aging management program is being used to identify and correct program elements that need improvement to maintain the quality performance of the program.

Conclusion

The enhanced Reactor Vessel Material Surveillance aging management program will provide reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.20 One-Time Inspection

Program Description

The One-Time Inspection aging management program will be a new condition monitoring program consisting of a one-time inspection of selected components to verify: (a) the system-wide effectiveness of an aging management program 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 will include: (a) determination of the sample size of components to be inspected based on an assessment of materials of fabrication, environments, plausible aging effects, and OE; (b) identification of the inspection locations in the system or component based on the potential for the aging effect to occur; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined; and (d) 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.

When one-time inspections fail to meet the established acceptance criteria, the Corrective Action Program will be used to schedule, track, and trend the appropriate corrective actions and follow up inspections. The inspections will include a representative sample of the system population and will focus on the bounding or lead components most susceptible to aging due to time in service, and severity of operating conditions. Twenty percent of the population with a maximum sample of 25 at each unit constitutes a representative sample size. A technical justification of the methodology used for determining sample size and for selecting components for inspection will be included in the One-Time Inspection program documentation. The program verifies either that unacceptable degradation is not occurring or triggers additional actions that will assure the intended function of affected components will be maintained during the subsequent period of extended operation.

Periodic inspections instead of this program will be 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 will be conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset, and surface conditions.

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 will be determined in accordance with the site's Corrective Action Program; however, no fewer than five additional inspections will be conducted for each inspection that did not meet acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less. For BFN, the additional inspections will include inspections at all the units with the same material, environment, and aging effect combination.

This new program will be implemented and inspections begin within 10 years before the subsequent period of extended operation.

NUREG-2191 Consistency

The One-Time Inspection aging management program will be consistent with the 10 elements of aging management program XI.M32, One-Time Inspection, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the One-Time Inspection Program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. A program effectiveness review was performed for the One-Time Inspection Program described in FSAR Section O.1.26 in support of preparing the BFN Subsequent License Renewal Application. The purpose of this program effectiveness review was to verify that the intent and the actions performed as part of the One-Time Inspection Program were met as required. The program included measures to verify the effectiveness of the aging management program and confirm the absence of the aging effects. The program validated the effectiveness of existing programs, and or confirmed that there is no need to manage aging related degradation for the period of extended operation. The One-Time Inspection Program was completed prior to entering the period of extended operation. A corporate self-assessment of the overall Aging Management Program was performed in 2022. That assessment determined that there was a programmatic Learning Opportunity associated with the One-Time Inspection Program related to the Carbon Steel and Uncontrolled Raw Water Programs.

   In 2014, pre-period of extended operation implementation of aging management activities associated with One-Time Inspection Activities aging management program was assessed by the site aging management program owner. Over 720 inspections were completed with no major problems observed and with the results documented in the One-Time Inspection Program Notebook and the Corrective Action Program as appropriate and summarized below.

- Inspections were performed for the plant Air / Gas related systems which includes air environments containing significant moisture. The inspections did not identify any indication of the specified aging effects, except for minor but acceptable corrosion on some non-ferrous piping, or find any indication of a slow acting or other aging effect that could affect the components during 60 years of operation, or the need for a scope increase. The inspections validated that material loss was not significant. It was concluded that one-time inspections were appropriate and no additional inspections or trending were required.
- Inspections were performed for the plant fuel oil related systems which includes the Fuel Oil System that supports the Diesel Generator System and High Pressure Fire Pump System for the related diesel generator. The inspections did not identify any indication of the specified aging effects, except for minor but acceptable corrosion on some non-ferrous piping, or find any indication of a slow acting or other aging effect that could affect the components during 60 years of operation, or the need for a scope increase. The inspections validated that material loss was not significant. It was concluded that one-time inspections were appropriate and no additional inspections or trending were required.
- Inspections were performed for the Lubricating Oil environment, which included two affected systems: the Radioactive Waste Treatment System and the Diesel Generator System. The inspections did not identify any indication of the specified aging effects, except for minor but acceptable corrosion on some non-ferrous piping, or find any indication of a slow acting or other aging effect that could affect the components during 60 years of operation, or the need for a scope increase. The inspections validated that material loss was not significant. It was concluded that one-time inspections were appropriate and no additional inspections or trending were required.
- Inspections were performed for the raw water environment which includes five affected systems: the Potable Water System, Heating, Ventilation, and Air Conditioning System, Raw Water Chemical Treatment System, Radioactive Waste Treatment System and the Radiation Monitoring System. Corrosion of aluminum alloy moisture traps in the Radiation Monitoring System, was identified. Degradation of the Unit 1 traps was initially identified by Operations as a result of heavier than expected water accumulation and was entered into the site Corrective Action Program. Additional inspections under the One-Time Inspection Program identified corrosion of similar traps in Unit 2 and Unit 3. These inspections confirm that the Corrective Action Program is identifying degraded components. Traps that were identified as degraded were replaced. Other than the aluminum traps in the Radiation Monitoring System, the raw water inspections for the non-ferrous, steel, and stainless steel components, the inspections did not identify any indication of the specified aging effects, except for expected but acceptable corrosion on steel components, or find any indication of a slow acting or other aging effect that could affect the components during 60 years of operation, or the need for a scope increase. The inspections validated that material loss was not significant. It was concluded that one-time inspections were appropriate and no additional inspections or trending were required. Steel components in the Radioactive Waste Treatment System floor and equipment drainage piping required aging management during the period of extended operation under a separate procedure.
- Inspections were performed for the treated water environment associated with the chemistry control program which includes the Auxiliary Boiler System, the Auxiliary

Decay Heat Removal System, the Radioactive Waste Treatment System, and heat exchangers in a portion of the Reactor Recirculation System. The inspections did not identify any indication of the specified aging effects, except for minor but acceptable corrosion on some non-ferrous and steel components, or find any indication of a slow acting or other aging effect that could affect the components during 60 years of operation, or the need for a scope increase. The inspections validated that material loss was not significant. It was concluded that one-time inspections were appropriate and no additional inspections or trending were required.

- Inspections were performed for the Torus, including submerged Torus components, and submerged concrete in the CCW pits. The inspections did not identify any indication of the specified aging effects, except for indications in one pit that were judged not to affect the structural integrity of the concrete structure, or find any indication of a slow acting or other aging effect that could affect the components during 60 years of operation, or the need for a scope increase. The inspections validated that material loss was not significant. It was concluded that one-time inspections were appropriate and no additional inspections or trending were required.
- Inspections were performed by volumetric examination of a sample of small bore Reactor Coolant Pressure Boundary (RCPB) piping and pipe fittings. The inspections looked for evidence of inside diameter cracking (e.g., due to cyclic loading) of carbon steel and stainless steel butt welds. A condition report was initiated as the result of a leak identified in the weld for the nozzle. The condition report required inspection of the entire population of similar configuration butt welds in the stainless steel piping. The cause of the crack was high residual stress exacerbated by the local environment and was repaired with a weld overlay. The remaining stainless steel butt welds on all three units were inspected by UT with no additional indications identified and no additional weld repairs required. The inspections did not identify any indication of the specified aging effects, except for the identified failure in the nozzle, or find any indication of a slow acting or other aging effect that could affect the components during 60 years of operation, or the need for a scope increase. The results of the inspections confirm the effectiveness of the ASME Section XI Inservice Inspection Subsections IWB, IWC and IWD Program and the Chemistry Control Program. However, augmented examination has been included in the ASME Section XI Inservice Inspection Subsections IWB, IWC and IWD Program for the overlay repair on the Unit 1 nozzle.
- Inspections were performed for the tank bottoms environment associated with the fuel oil tanks for the diesel generators and the condensate storage tanks. A pinhole size leak was found in the tank bottom of the diesel fuel oil tank for the high pressure fire protection diesel-driven pump. A condition report was generated and tank replacement was identified as the corrective action. Until the tank is replaced, the leak, measured in drops per minute; and tank level are being monitored. Periodic inspection of the tank bottom was established as a corrective action. With the exception of the diesel fuel oil tank for diesel-driven high pressure fire pump, the inspections did not identify any indication of the specified aging effects, or find any indication of a slow acting or other aging effect that could affect the components during 60 years of operation, or the need for a scope increase. The results of the inspections confirm the effectiveness of the Fuel Oil Chemistry and Chemistry Control programs. However, periodic monitoring of the wall thickness for the bottom of the diesel fuel oil storage tank for the high pressure diesel-driven fire pump has been incorporated into the program as an enhancement. The diesel fuel oil storage tank for the high pressure diesel-driven fire pump was replaced in 2013.

In 2012 and 2013, pre-period of extended operation implementation of the One-Time Inspection program was assessed by the NRC. The NRC staff reviewed the information provided for license renewal and determined that the One-Time Inspection program would adequately manage aging of applicable components during the period of extended operation at BFN.

The operating experience relative to the One-Time Inspection program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking and loss of material. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. Therefore, there is confidence that implementation of the One-Time Inspection program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

Conclusion

The new One-Time Inspection program will provide reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.21 Selective Leaching

Program Description

The Selective Leaching aging management program is a new condition monitoring program that includes a one-time inspection for components exposed to closed cycle cooling water and treated water environments, as well as opportunistic and periodic inspections for components exposed to raw water, waste water, and soil environments. Visual inspections supplemented by mechanical examination techniques such as chipping or scraping (for ductile and gray cast iron components) will be conducted. Periodic destructive examinations of components for physical properties (i.e., degree of dealloying, depth of dealloying, through wall thickness, and chemical composition) will be conducted for components exposed to raw water, waste water, and soil environments. Inspections and tests are 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.

Components in the scope of the Selective Leaching aging management program include piping and piping components, valve bodies, pump casings, heat exchanger components, and other components that are constructed of materials and are located in environments that may be susceptible to selective leaching. Materials susceptible to selective leaching which are in the scope of this program are gray cast iron, ductile iron, and copper alloys containing greater than 15 percent zinc. Copper alloys containing greater than 8 percent aluminum (aluminum bronze) are also susceptible to selective leaching. Environments that promote susceptibility to selective leaching include raw water, closed cycle cooling water, treated water, waste water, and soil.

For the one-time and periodic/opportunistic portions of the program, visual inspections will be conducted on a representative sample of components of each material and environment combination of components. A representative sample consists of three percent of each material and environment population per unit or a maximum of 10 components per population per unit.

Additionally, for the periodic/opportunistic portion of the program, two destructive examinations will be performed per population per unit for sample populations with greater than 35 susceptible components, or one destructive examination will be performed per population per unit for sample populations with less than or equal to 35 susceptible components. For periodic/opportunistic inspection, 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.

Inspections are conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset and surface conditions as appropriate. 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. The number of additional inspections will be equal to the number of failed inspections for each material and environment population with a minimum of five additional visual and mechanical inspections when visual and mechanical inspection(s) do not meet acceptance criteria, or 20 percent of each applicable material and environment combination inspected, whichever is less, and a minimum of one additional destructive examination when destructive examination(s) do not meet acceptance criteria. 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.

This new program will be implemented and inspections begin within 10 years before the subsequent period of extended operation.

NUREG-2191 Consistency

The new Selective Leaching aging management program will be consistent with the 10 elements of aging management program XI.M33, Selective Leaching, specified in NUREG-2191.

Exceptions to NUREG-2191

None

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Selective Leaching program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. During an inspection in August 2011, the Emergency Diesel Generator (EDG) cooling water temperature control valve for the D Diesel Generator had indications of selective leaching in the valve internals. This issue was entered into the Corrective Action Program. The valve was replaced and the temperature control valves on the remaining seven EDGs were inspected. There were no other indications of selective leaching identified. As part of the associated corrective actions, the EDG temperature control valves will continue to be periodically inspected for indications of selective leaching under the preventive maintenance (PM) program. Procedures for the Standby Diesel Engine Six Year Inspection and for the Standby Diesel Engine Twelve Year Inspection are used to conduct the required periodic inspections of the temperature control valves and both procedures contain selective leaching inspection instructions. Both of these procedures contain requirements to initiate a Condition Report if selective leaching deterioration is observed. These procedures are scheduled and performed in accordance with the PM program.

   This operating experience demonstrates that the Corrective Action Program is being used to document indications of selective leaching as well as deficiencies identified during the conduct of the EDG six and twelve year inspections. Due to the procedural requirement to document any evidence of deterioration in a condition report, it is concluded that future selective leaching issues identified with the EDG temperature control valves would be documented and resolved by the use of the Corrective Action Program. This will ensure that these components will continue to perform their intended functions, and that appropriate aging management will be performed during the subsequent period of extended operation.

2. During an initial License Renewal inspection, the EDG “D” heat exchangers revealed potential indications of selective leaching at the tube-to-tubesheet interface. The condition was entered into the Corrective Action Program. These heat exchangers were replaced and a laboratory analysis was performed to positively identify whether selective leaching was present. The laboratory analysis determined that the corrosion was not selective leaching.

   This operating experience demonstrates potential selective leaching issues are addressed by the Corrective Action Program and proper analysis is performed to determine selective leaching presence.

Conclusion

The new Selective Leaching program will provide reasonable assurance that the loss of material aging effect will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.22 ASME Code Class 1 Small-Bore Piping

Program Description

The BFN ASME Code Class 1 Small-Bore Piping aging management program is a new conditioning 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 nominal pipe size 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. The program includes measures to verify that degradation is not occurring; thereby either confirming that there is no need to further manage aging-related degradation or validating the effectiveness of existing programs and practices for the second period of extended operation.

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 and socket welds) for plants that have not experienced cracking of ASME Code Class 1 small-bore piping 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) for plants that have experienced cracking of ASME Code Class 1 small-bore piping and have not implemented corrective actions to effectively mitigate the cause(s) of the cracking.

The operating experience relative to the ASME Code Class 1 Small-Bore Piping program did not identify an adverse trend in performance. The inspection methods being implemented by the program have been proven effective in detecting aging effects including cracking. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degradation is found. There have been 3 cracks identified in small bore butt welds; two on Unit 1, one on Unit 2, and none on Unit 3. These cracks were identified using non-destructive UT and VT-2 examinations. Two cracks were identified prior to leaking while one crack was identified leaking during the Primary System Leakage Test. BFN effectively mitigated the cracks propagating further by adding weld overlays in accordance with ASME Section XI Non-Mandatory Appendix Q, as specified by Regulatory Guide 1.147, Revision 15 at the time the overlays were applied. For these welds with overlays, 25% of each units' population of ASME Section XI Non-Mandatory Appendix Q welds are examined once every 10 years. BFN also implemented Owner Elected inspections to inspect the N10 Safe-end to Tee, and N11A, N11B, N12A, N12B, N16A, and N16B Nozzle Safe-end to Pipe Welds, that have not been overlaid, every refueling outage via UT.

Volumetric examinations will employ techniques that have been demonstrated to be capable of detecting flaws and discontinuities in the examination volume of interest. Because more information can be obtained from a destructive examination than from a nondestructive volumetric examination, any weld that is destructively examined can be credited as equivalent to having volumetrically examined two welds. If cracking is revealed by a one-time inspection, the condition will be entered into the Corrective Action Program and additional one-time inspections will be performed for the population of welds (butt welds or socket welds) that have experienced cracking in accordance with ASME Section XI, Subarticle IWB-2420; and periodic inspections will be performed in accordance with NUREG-2191, Table XI.M35-1, Category C.

In addition to the periodic inspections described above, the following table provides a summary of the number of one-time inspections required for Units 1, 2, and 3 butt welds and socket welds:

Unit	Type of Weld (Butt or Socket)	Category per Table XI.M35-1	Percent/ Number Requiring One-Time Inspection	Number of Welds in the Population	Number of One-Time Weld Inspections Required
1	Butt Welds	B	10% up to 25	91	10
1	Socket Welds	A	3% up to 10	More than 1000	10
2	Butt Welds	B	10% up to 25	91	10
2	Socket Welds	A	3% up to 10	More than 1000	10
3	Butt Welds	A	3% up to 10	91	3
3	Socket Welds	A	3% up to 10	More than 1000	10

This new program will be implemented and one-time inspections will be performed within the six year period prior to the subsequent period of extended operation.

NUREG-2191 Consistency

The ASME Code Class 1 Small-Bore Piping aging management program will be consistent with the 10 elements of aging management program XI.M35, ASME Code Class 1 Small-Bore Piping, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the new BFN ASME Code Class 1 Small-Bore Piping aging management program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation through walkdowns and opportunistic inspections.

1. On May 5, 2012, an apparent cracked weld at a 1 inch Unit 3 Residual Heat Removal (RHR) test valve was identified during the ASME Section XI System Pressure Test, and documented

in the Corrective Action Program. The leak was first isolated by closing manual isolation valves and later repaired under a work order.

This is an example of how inservice inspections will be an appropriate method for monitoring the condition of small-bore piping and that use of the Corrective Action Program is an effective process for correcting identified deficiencies.

2. Due to rising unidentified leakage rate in Unit 2 drywell on August 3, 2014, an entry was made with the reactor at approximately 13% power. During this entry, a leak was identified downstream from a 20-inch Unit 2 RHR flow control valve, which is located at or near the interface of the two inch chemical injection and drain line and inside primary containment. The leak location is upstream from a 2-inch RHR valve. The leak was documented in the Corrective Action Program. A work order was then generated to repair the leak and a service request was generated to clean and visually inspect the rouging of the stainless steel piping, valves and insulation.

   This is an example of how leakage rate monitoring will be an appropriate method for monitoring the condition of small-bore piping and that use of the Corrective Action Program is an effective process for correcting identified deficiencies.

3. During the reactor vessel leakage test on March 26, 2017, a small through wall leak in the 1-inch piping between a primary penetration location and a flow element was identified and documented in Corrective Action Program. A work order was generated to repair the instrument line, the work was completed and the work order was closed.

   This is an example of how inservice testing will be an appropriate method for monitoring the condition of small-bore piping and that use of the Corrective Action Program is an effective process for correcting identified deficiencies.

4. On October 15, 2020, during Ultrasonic Test (UT) examination of the Unit 1 safe end to pipe weld on an instrument line connected to pressure vessel nozzle and connecting upstream of a primary containment penetration, a circumferential indication was identified. The indication was approximately 0.8 inches in length and not through wall. The indication was on the safe end side of the weld. The safe end weld is part of the Standby Liquid Control system and is ASME Code Class 1 equivalent piping. This inspection is required as a result of a previous through wall leak documented in Corrective Action Program and is performed every outage. A work order was generated to Implement a design engineering change which repaired the damaged areas.

   This is an example of how inspections will be an appropriate method for monitoring the condition of small-bore piping and that use of the Corrective Action Program is an effective process for correcting identified deficiencies.

5. A Condition Report was generated on May 3, 2011, to evaluate operating experience (OE) from Monticello for applicability and utilization at BFN. Monticello had identified the existence of a limited number of small-bore stainless steel butt weld connections less than 4 inches in diameter and as a result changed the one-time inspection commitment to include piping butt welds with 2 inch nominal pipe size through less than 4 inch nominal pipe size. As a result of this OE, BFN reviewed the design drawings and bill of materials to determine the population of carbon steel butt welds that exist within the reactor coolant pressure boundary between 2 inches and 4 inches nominal pipe size. Using the initial License Renewal One-Time Inspection program, BFN conducted a one-time inspection of these identified butt welds and stainless steel butt welds between 2 inches and 3 inches in the Reactor Coolant Pressure Boundary. These inspection results identified the aging effect had the potential to occur during the period of extended operation and the original sample inspection scope was increased. The results of the increased inspections confirmed program effectiveness in preventing butt

weld cracking. However, as an additional conservative action, augmented examination was included for the weld overlay repair on Unit 1 nozzle N11B.

This is an example of how BFN plans to continue to evaluate OE generated at other plants as an effective method for maintaining components intended functions.

6. A Condition Report, dated October 20, 2020, documented an aging related crack that was found on the safe end to pipe weld is part of the Standby Liquid Control system in Unit 1. This crack was identified prior to a leak occurring using an UT inspection which is a non-destructive test. A design change was issued to add a weld overlay to prevent the identified crack from propagating.

   This example shows how BFN will be able to identify cracks in butt welds prior to a leak occurring.

7. A Condition Report, dated May 13, 2009, documented a planar flaw that exceeded the acceptance criteria of ASME Section XI, Table IWB-3514-2 in the Unit 2 Reactor Vessel Instrumentation Nozzle N12A safe end to pipe weld. This crack was identified prior to a leak occurring using an UT inspection. As a result, BFN added weld overlays to similar welds on all three units and put in place preventative maintenance inspections to inspect the nozzle welds every refueling outage.

   This example shows how BFN will be able to identify cracks in butt welds prior to a leak occurring.

<u>Conclusion</u>

The new ASME Code Class 1 Small-Bore Piping program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.23 External Surfaces Monitoring of Mechanical Components

<u>Program Description</u>

The new BFN External Surfaces Monitoring of Mechanical Components aging management program will consist of periodic visual inspections of metallic, and polymeric components, such as piping, piping components, ducting, ducting components; heating, ventilation, and air conditioning (HVAC) closure bolting; heat exchanger components, and seals. There are no cementitious components within the scope of this program. The program will use visual inspections to manage the aging effects of loss of material, cracking, hardening or loss of strength, reduced thermal insulation resistance, loss of preload for HVAC closure bolting, and reduction of heat transfer due to fouling. In addition, physical manipulation will be used to manage hardening or loss of strength and reduction in impact strength. For coated surfaces, confirmation of the integrity of the coating will be used to manage the effects of corrosion on the metallic surface. Loss of material due to boric acid corrosion is not an applicable aging effect for BFN managed by the External Surfaces Monitoring of Mechanical Components program.

Acceptance criteria will be defined to ensure that the need for corrective actions will be identified before loss of intended functions. Evaluations of as-found conditions will include confirmation that intended functions will be maintained given the projected degradation rate and the timing of subsequent inspections. Additionally, sample selection, size and frequency will be confirmed to maintain intended functions as applicable based on the projected degradation rate. For quantitative analyses, the required minimum wall thickness to meet the applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color and other indicators will be addressed.

General system inspections and walkdowns each refueling cycle.

Inspections will be performed during system inspections and walkdowns by personnel qualified in accordance with station procedures and programs to perform the specified task. When required by the ASME Code, inspection will be conducted in accordance with the applicable code requirements. Non-ASME Code inspections and tests will follow site procedures that include inspection parameters for items such as lighting, distance, offset, surface coverage, and presence of coatings.

Reduced thermal insulation resistance due to moisture intrusion, associated with insulation that is jacketed, will be managed by visual inspection of the condition of the jacketing when the insulation has an intended function to reduce heat transfer from the insulated components. External visual inspections of the metallic insulation jacketing that have been installed in accordance with BFN procedures that include configuration features will be conducted to detect damage to metallic jacketing that would permit moisture intrusion.

The system inspections and walkdowns that can detect age-related degradation will be performed at a frequency not to exceed one refueling cycle. This frequency accommodates inspections of components that may be in locations normally accessible only during outages (e.g., high dose areas). Surfaces that are not readily visible during plant operations and refueling outages are inspected when they are made accessible and at such intervals that would ensure the components' intended functions are maintained.

Periodic inspection for cracking in copper alloy (>15% Zn or >8%Al), SS, or aluminum components every 10 years

Periodic visual inspections or surface examinations are conducted to detect cracking in copper alloy (>15% Zn or >8%Al), SS, or aluminum components every 10 years during the subsequent period of extended operation using one or more of the following options to implement the periodic visual inspections or surface examinations:

- Surface examination conducted in accordance with BFN specific procedures.
- ASME Code, 2007 Edition through 2008 Addenda as modified by 10CFR50.55a, Section XI, Appendix VIII VT-1 examinations (including those inspections conducted on non-ASME Code components).

Surface examinations or VT-1 examinations will be conducted on 20 percent of the surface area unless the component is measured in linear feet, such as piping. If the component is measured in linear feet any combination of 1-foot length sections and components will be used to meet the recommended extent of 25 inspections.

Periodic inspection of metallic insulation jacketing every 10 years

Component surfaces that are insulated and exposed to condensation and insulated outdoor components will be periodically inspected every 10 years during the subsequent period of extended operation. Inspections will be conducted routinely or seasonally for each material type and environment where condensation or moisture on the surfaces of the component could occur.

In some instances, significant moisture can accumulate under insulation during high humidity seasons, even in conditioned air.

A minimum of 20 percent of the in-scope piping length, or 20 percent of the surface area for components whose configuration does not conform to a 1-foot axial length determination will be inspected after the insulation is removed. Alternatively, any combination of a minimum of twenty-five (25) 1-foot axial length sections and components for each material type will be inspected.

NUREG-2191 Consistency

The External Surfaces Monitoring of Mechanical Components aging management program will be consistent with the 10 elements of aging management program XI.M36, External Surfaces Monitoring of Mechanical Components, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the External Surfaces Monitoring of Mechanical Components program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. On April 18, 2022, a Condition Report was entered into the Corrective Action Program due to severely degraded piping found between a 1/2 inch vent valve and 4 inch discharge piping from the 3B chilled water pump. This was discovered during the performance of other maintenance. A work order was generated to replace the 1/2 inch piping and valve. This work order has approved for work in 2024 during the Unit 3 refueling outage before the 3B chiller is returned to service.

   This example provides objective evidence that opportunistic inspections will be an appropriate method for monitoring the condition of external surfaces and that use of the Corrective Action Program is an effective process for correcting identified deficiencies.

2. On February 7, 2012, a Condition Report was entered into the Corrective Action Program due to damaged insulation being discovered during a walkdown on the chilled water piping located inside the Control Bay chillers enclosure on top of the Diesel Generator Building, which resulted in water penetration to the piping. A work order was generated and the damaged insulation has been replaced.

   This example provides objective evidence that inspections conducted during walkdowns will be an appropriate method for monitoring the condition of external surfaces including insulation and that use of the Corrective Action program is an effective process for correcting identified deficiencies.

3. On January 26, 2012, a Condition Report was entered into the Corrective Action Program to repair coating on the Residual Heat Removal Service Water return line due to corrosion damage caused by a through wall leak that had been previously identified in the Corrective

Action Program and repaired. The coating damage was identified during a quarterly walkdown, and the coating was subsequently repaired.

This example provides objective evidence that periodic inspections will be an appropriate method for monitoring the condition of external surfaces and that use of the Corrective Action Program is an effective process for correcting identified deficiencies.

4. On February 5, 2013, a Condition Report was entered into the Corrective Action Program due to rusting fire protection piping being identified in the transformer yard during a walkdown. Service Requests were written in the Corrective Action Program to clean and paint the fittings. Work orders completed the work to clean and paint the piping and associated fittings.

   This example provides objective evidence that inspections conducted during walkdowns will be an appropriate method for monitoring the condition of external surfaces including insulation and that use of the Corrective Action Program is an effective process for correcting identified deficiencies.

Conclusion

The new External Surfaces Monitoring of Mechanical Components program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.24 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

Program Description

The BFN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components aging management program is a new condition monitoring program that manage loss of material and cracking, as well as hardening or loss of strength of polymeric materials. Reduction of heat transfer due to fouling will also be managed.

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will consist of inspections of the internal surfaces of piping, piping components, ducting, heat exchanger components, and other components. Applicable environments include air, air with borated water leakage, condensation, gas, diesel exhaust, fuel oil, and any water-filled systems. Aging effects associated with elastomers and flexible polymeric components installed in open-cycle cooling water, closed-cycle cooling water, and fire water systems will be managed by this program in lieu of the other BFN programs. This program also encompasses the requirements that were previously included in the Carbon Steel/Raw Uncontrolled Water program.

These internal inspections will be performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. The program will include visual inspections and when appropriate, surface examinations. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength will be used to augment the visual examinations conducted under this program. This program may also be used to manage cracking due to stress corrosion cracking (SCC) in stainless steel (SS) components exposed to aqueous solutions and air environments containing halides. This program will not be used to manage components where visual inspection of internal surfaces is not possible. At a minimum, in each 10-year period during the subsequent period of extended operation, a representative sample of 20 percent of the population or a maximum of 25 components per population (defined as components having the same combination of material, environment, and aging effect) will be inspected for the in-scope aging effects at each unit, unless the technical justification allows for reducing sample size.

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. Surface examinations or ASME Code, 2007 Edition through 2008 Addenda as modified by 10 CFR 50.55a, Section XI, Appendix VIII VT-1 examinations will be conducted to detect cracking of SS components and opportunistic inspections will continue in each period despite meeting the sampling limit. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength will be used to augment the visual examinations conducted under this program.

Internal visual inspections used to assess loss of material will be capable of detecting surface irregularities that could be indicative of an unexpected level of degradation due to corrosion and corrosion product deposition. Where such irregularities are detected for steel components exposed to raw water, raw water (potable), or wastewater, follow-up volumetric examinations will be performed. Inspections not conducted in accordance with ASME Code, 2007 Edition through 2008 Addenda as modified by 10 CFR 50.55a, Section XI, Appendix VIII requirements will be conducted in accordance with plant-specific procedures including inspection parameters such as lighting, distance, offset and surface conditions. Acceptance criteria will be such that the components will meet its intended function until the next inspection or the end of the subsequent period of extended operation. Qualitative acceptance criteria will be clear enough to reasonably assure a singular decision is derived based on observed conditions. Corrective actions will be performed as required based on the inspection results.

This program is also used to managed cracking due to SCC in stainless steel components exposed to aqueous solutions. Internal coatings of tanks are not managed by this program. This program is not used to manage components where visual inspections of internal surfaces is not possible unless specific volumetric inspections are performed as noted above.

For loss of material due to recurring internal corrosion, the frequency and extent of wall thickness inspections will be increased to commensurate with the significance of the degradation. 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 inspections will be increased in accordance with the BFN Corrective Action Program; however, no fewer than five additional inspections are conducted for each inspection that did not meet the acceptance criteria, or 20 percent of each applicable material, environment, and aging effect combination is inspected, whichever is less.

A review of plant-specific OE for recurring internal corrosion (See Sections 3.2.2.2.7, 3.3.2.2.7, and 3.4.2.2.6) for systems and components which credit the BFN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program did not identify recurring internal corrosion. In the event of future discovery of recurring internal corrosion, for systems and components within the scope of this program, BFN will implement a plant-specific program to manage the recurring aging effects of the applicable systems and components as part of the corrective actions. Following a failure due to recurring internal corrosion, this program may be used if the failed material is replaced by one that is more corrosion resistant in the environment of interest, or corrective actions have been taken to prevent recurrence of the recurring internal corrosion.

This new program will be implemented no later than six months prior to the subsequent period of extended operation.

NUREG-2191 Consistency

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will be consistent with the 10 elements of aging management program XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, specified in the NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. On August 16, 2012, a condition was entered into the Corrective Action Program due to Raw Cooling Water (RCW) piping on Unit 3 found to be blocked with corrosion product build-up during a raw water inspection. A Work Order was initiated and completed to replace the small bore piping.

   This example provides objective evidence that current opportunistic inspections are effective in identifying and managing aging effects associated with the internal surfaces in miscellaneous piping and ducting components that will be managed by the BFN Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program.

2. On February 20, 2013, a through wall leak in RCW piping was identified during a system engineering walk down and entered into the Corrective Action Program. Under deposit corrosion was the suspected cause. A Work Order was created to correct this defect and the piping was replaced.

   This example provides objective evidence that inspections conducted during walkdowns will be an appropriate method for visual inspections for monitoring the condition of components within the scope of the program and that use of the Corrective Action Program is an effective process for correcting identified deficiencies.

3. On November 21, 2014, a condition was entered into the Corrective Action Program due to a wall thickness below nominal wall being identified on the RHRSW system as part of preparation to install a welded FLEX connection to a portion of the B3 RHRSW pump piping at the intake pumping station. Ultrasonic test measurements were taken of the piping to assess the as-found condition. The scan revealed two areas with a nominal wall thickness within the pipe. Therefore, the condition was reviewed and evaluated. The cause was attributed to the

normal wear of piping over time due to corrosion via general corrosion and pitting corrosion. The piping subsequently was replaced as part of a modification.

This example provides objective evidence that inspections conducted during walkdowns will be an appropriate method for visual inspections for monitoring the condition of components within the scope of the program and that use of the Corrective Action Program is an effective process for correcting identified deficiencies.

4. On June 29, 2016, a condition report was entered into the Corrective Action Program after reviewing OE from Oyster Creek EDG hose failure. In January 2016, Oyster Creek had a flexible hose that connects the jacket water expansion tank to the suction of the jacket water pump catastrophically fail on one of their Electro-Motive Diesel Model 645 Emergency Diesel Generators (EDG). Similar hoses exist on all Electro-Motive Diesel Model 645 engines, so this OE was directly applicable to the TVA Electro-Motive Diesel EDG population. The cause of the failure at Oyster Creek was age related degradation. The failed hose at Oyster Creek was not replaced under the existing 12-year preventive maintenance hose replacement work. This was due to the absence of an inventory or sign-off list that would have prompted replacement of each hose, ultimately resulting in the failure. TVA Nuclear plants reviewed this OE item and made appropriate changes to the relevant maintenance procedures to ensure all flexible connections are replaced at the proper periodicity.

   This example provides evidence of the ongoing review of industry OE to ensure that the aging management program is effective in managing the aging effects for which it is credited.

Conclusion

The new Inspection of Infernal Surfaces in Miscellaneous Piping and Ducting Components program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.25 Lubricating Oil Analysis

Program Description

The Lubricating Oil Analysis aging management program is a new condition monitoring program that provides monitoring of oil condition to manage loss of material and reduction of heat transfer in piping, piping components, gear boxes, heat exchangers, and tanks within the scope of subsequent license renewal exposed to a lubricating oil environment. Sampling and analysis activities identify specific wear products and verify the contamination levels (primarily water and particulates) and the physical properties of lubricating oil are maintained within acceptable limits consistent with vendor or industry guidelines (e.g., American Society of Testing Materials (ASTM) D 6224-02) to ensure that component intended functions are maintained.

The program includes sampling, analyses, and trending activities which preserve an environment that is not conducive to loss of material or reduction of heat transfer. The lubricating oil sampling and analysis activities identify detrimental contaminants such as water, sediments, specific wear elements, and elements from an outside source. Oil analyses that do not meet acceptance criteria are evaluated in accordance with the program requirements and the Corrective Action Program. The contaminant levels are trended in the program's database, and recommendations are made when adverse trends are observed, which could indicate in-leakage or corrosion product buildup.

The program applies monitoring methods that are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent degradation that would affect a component's ability to perform its intended function.

To verify the effectiveness of the Lubricating Oil Analysis program, selected components will be inspected as described in the One-Time Inspection program, to ensure that degradation is not occurring and component intended functions are maintained during the subsequent period of extended operation. The One-Time Inspection program is described in Section B.2.1.20.

This new program will be implemented no later than six months prior to the subsequent period of extended operation.

<u>NUREG-2191 Consistency</u>

The Lubricating Oil Analysis aging management program will be consistent with the 10 elements of aging management program XI.M39 Lubricating Oil Analysis, specified in NUREG-2191.

<u>Exceptions to NUREG-2191</u>

None.

<u>Enhancements</u>

None.

<u>Operating Experience</u>

The following examples of operating experience provide objective evidence that the new BFN Lubricating Oil Analysis aging management program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. BFN Emergency Diesel Generators (EDG) lubricating oil filter age is tracked. In January 2011, it was identified that lubricating oil filter age for six of the eight EDG exceeded, or would exceed, the 30 months vendor recommendation by the time of scheduled replacement. This condition was entered into the Corrective Action Program, and actions were taken by BFN in accordance with vendor recommendations to evaluate EDG oil filters at 30 months of age to identify any degradation. A Work Order was created to collect and perform lube oil analysis on each of the filters which exceeded 30 months to ensure no signs of filter media breakdown prior occurred prior to filter replacement. The sample was collected one week prior to each monthly operability run and interpreted for signs of lube oil filter breakdown. The oil analysis was performed and confirmed no oil filter breakdown, and that the oil filters remained effective prior to replacement. This is an example of how the Corrective Action Program is effective in identifying deficiencies and to perform additional monitoring.

   This operating experience provides confidence that implementation of the new Lubricating Oil Analysis aging management program will effectively maintain the required oil quality to prevent or mitigate age-related degradation of components within the scope of the program during the subsequent period of extended operation.

2. Oil samples collected at the conclusion of an uncoupled run of the 1A Core Spray Motor in October 2014 exceeded the acceptance criteria for in-service oil. This condition was entered into the Corrective Action Program. The oil reservoir was flushed and the oil changed out. An acceptable sample result was obtained after the coupled run. This is an example that BFN

existing lubricating oil sampling activities and the Corrective Action Program are effective in identifying and correcting deficiencies.

This operating experience provides confidence that implementation of the new Lubricating Oil Analysis aging management program will effectively maintain the required oil quality to prevent or mitigate age-related degradation of components within the scope of the program during the subsequent period of extended operation.

3. During a Preventative Maintenance activity in February 2018, an oil sample was obtained from the 2A Control Rod Drive (CRD) Pump Speed Increaser. The oil was sampled for wear metals due to an unusually dark appearance. The sample results showed elevated wear metals normally associated with Babbitt bearings and journals. This condition was entered into the Corrective Action Program. As a result, corrective actions were taken. These actions included draining, cleaning and inspecting the gear box, replacing bearings, flushing the oil cooler, and cleaning the oil pump. The CRD pump was returned to service and declared satisfactory.

   This is an example that preventative maintenance is an appropriate method for managing aging in oil environments, as well as utilizing the Corrective Action Program for identifying, documenting, and correcting deficiencies.

4. The result from an oil sample taken in August 2018 from Unit 1 High Pressure Coolant Injection (HPCI) System showed an increased moisture content. A Condition Report in the Corrective Action Program was written to document an increasing moisture trend over the last three oil samples. Although no administrative limits on moisture were exceeded, corrective actions were performed based on the adverse trend. The Unit 1 HPCI System was walked down to inspect the condition of the insulation around the shaft seals and bearing housings. It was identified that the insulation covered more area than desired. This condition created the path for any water or vapor from the shaft seals to enter the bearing oil drain. Insulators made adjustments to open the space around the seals and bearings to correct this condition. A portable water removal filter system was placed in service to filter the water out of the oil. This was completed and post-filtering moisture content was reduced from 0.14% to 0.0623%.

   This is an example that BFN is effectively monitoring oil environments through periodic sampling. Corrective activities conducted by qualified individuals will be effective in monitoring the condition of the oil environments, and correcting any deficiencies.

5. In July 2022, during Unit 1 Quarterly HPCI surveillance testing, the governor valve failed to open after operators placed the auxiliary oil pump into service in accordance with procedure. This was documented in the Corrective Action Program. The Electronic Governor (EG-R) was replaced, and following testing, HPCI was returned to Operable status. During a scheduled Unit 1 HPCI outage in October 2018, the EG-R was inspected. No adverse findings were documented. Following the failure of the Unit 1 EG-R in July of 2022, photographs of the internals of the EG-R, taken during the October 2018 EG-R inspections, were reviewed and clearly showed corrosion and indications of water contamination. The conditions identified in the photographs went unreported until observed following the failure in July 2022. Additionally, In December 2021, EPRI published notes on the August 2021 Terry Turbine Users Group meeting in which industry experts reviewing operating experience and empirical data changed the condition monitoring limit for moisture in Terry turbine control oil from 0.5% to 0.05% by mass. The new limits were needed as oil with moisture at or above the 0.05% level is subject to water dropout and this water will be in the entire oil system, including the EG-R, and will remain there until the next run of the HPCI system, normally quarterly. Water in the EG-R will quickly cause corrosion and potentially led to blockage of small passages and needle valves. BFN engineering personnel were aware of the new limits, but actions were not taken to

incorporate those limits in plant procedures and processes. In October 2021, the BFN personnel discovered a rising trend in HPCI control oil moisture with the value exceeding 0.05%. No additional actions were taken for moisture at this level, as the new limits had not been incorporated. Following the EG-R failure in July 2022, corrective actions were taken to strengthen the existing lubricating oil analysis and monitoring procedures and practices to prevent recurrence including several procedure changes. The Lubrication Oil Analysis and Monitoring Program procedure was revised to set the moisture limit of both the HPCI and Reactor Core Isolation Cooling (RCIC) to 0.05%. Additional actions were added to the procedure to direct moisture removal for moisture levels above 0.025%, and to flush the EG-R if moisture levels exceed 0.05%. Additional changes were made to the HPCI turbine preventative maintenance procedure. This procedure change included photographic examples of an EG-R with corrosion and one that is acceptable. This enhancement improves the ability to detect corrosion in the EG-R. This is an example of how the Corrective Action Program is effective in correcting program deficiencies in the existing lubricating oil analysis and monitoring procedures and practices.

This operating experience provides confidence that implementation of the new Lubricating Oil Analysis aging management program will effectively maintain the required oil quality to prevent or mitigate age-related degradation of components within the scope of the program during the subsequent period of extended operation.

<u>Conclusion</u>

The new Lubricating Oil Analysis Program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.26 Monitoring of Neutron-Absorbing Materials Other Than Boraflex

<u>Program Description</u>

The BFN Monitoring of Neutron-Absorbing Materials other than Boraflex aging management program is a new condition monitoring program that manages the effects of aging on neutron-absorbing components/materials other than Boraflex used in spent fuel racks. The spent fuel racks at BFN utilize Boral cermet for the neutron-absorbing material in the spent fuel racks.

The Monitoring of Neutron-Absorbing Materials Other Than Boraflex AMP monitors changes in condition of the Boral material in the spent fuel storage racks through visual inspections, dimensional measurements, neutron-attenuation testing, and weight and specific gravity measurements of representative test coupons. The primary measurements used to characterize performance of the Boral coupons are dimensional measurements (to detect bulging or swelling) and neutron-attenuation testing (to confirm the boron-10 areal density). Results of each coupon surveillance are documented and retrievable for purposes of trending. Acceptance criteria thresholds are established as indicators of potential adverse trends in the condition of the Boral material to ensure corrective actions are taken prior to compromising the 5% sub-criticality margin as contained within the spent fuel storage pool criticality analysis. The maximum interval between each inspection is not to exceed 10 years, regardless of operating experience.

This new aging management program will be implemented no later than six months prior to the subsequent period of extended operation.

NUREG-2191 Consistency

The Monitoring of Neutron-Absorbing Materials other than Boraflex aging management program will be consistent with the 10 elements of aging management program XI.M40, Monitoring of Neutron-Absorbing Materials other than Boraflex, as specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Monitoring of Neutron-Absorbing Materials Other Than Boraflex program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. BFN placed a total of 16 coupons in the Unit 3 Spent Fuel Storage Pool in October 1983. The coupons supplied by the rack manufacturer are of the same metallurgical condition as the boral plates used in the High Density Fuel Storage Racks in thickness, chemistry, finish, and temper. The test coupons located in the Unit 3 Spent Fuel Storage Pool are representative of all three BFN units. For the first six years of the planned 15 year surveillance program, examination was to have taken place at two year intervals. Accordingly, two coupons were removed in October 1985. Blisters were found upon examination, and because of this unexpected anomaly, three additional coupons were removed in December 1985 for further evaluation. As a result of blisters found on the coupons removed in 1985, the surveillance program was expanded to include monitoring the formation and behavior of these blisters. The surveillance frequency is required to be re-evaluated each time this instruction is performed and will not exceed 10 years. The surveillance program is currently conducted in accordance with procedures.

   This operating experience demonstrates use of the Corrective Action Program to enhance the surveillance program based on surveillance results.

2. The most recent physical inspection of the BFN Boral Cermet coupons was performed September 2017 in accordance with BFN procedures in support of the BFN Extended Power Uprate Licensing Amendments. The procedure specifies the frequency shall be determined based on the test results but shall not exceed 10 years. During this performance all measurements were within specification. There was minor growth of existing blisters noted. The Boral Cermet was deemed satisfactory, there were no indications of corrosion on aluminum outer surfaces and no visible anomalies were noted.

   This operating experience demonstrates proper material condition of the Boral Cermet plates and implementation of the surveillance program.

3. Neutron attenuation measurements were taken on a test coupon in November 2017 in support of BFN Extended Power Uprate Licensing Amendments. Results of the evaluation of a BFN coupon from the spent fuel pool were document in a report, dated March 19, 2019. Visual and dimensional results indicate the surveillance coupon was in general good condition with slight occurrences of blisters typical of Boral as known throughout the industry. The coupon displayed slight superficial oxidation discoloration, expected for a coupon of this age. No

significant corrosion loss of edge material was observed. Neutron attenuation testing was also performed. The post-irradiation neutron attenuation measurements of B-10 areal density at nine unique locations were uniform across all areas of the coupon with an averaged result of 0.0153 grams $^{10}B/cm^2$ nominally and a minimum areal density (-3 σ) of 0.0149 grams $^{10}B/cm^2$. This agreed with neutron attenuation measurements taken of archive samples of the same material lot that have never been in the spent fuel pool. Direct measurements of neutron attenuation of blistered spots indicated no loss of B-10 areal density within the blistered area. The coupons measured B-10 areal density was found to be uniform and exceeded the minimum areal density value of 0.0130 $^{10}B/cm^2$ specified in the BFN FSAR Section 10.3.

This operating experience demonstrates proper material condition of the Boral Cermet plates.

4. A review of the TVA Operating Experience Program evaluations of external operating experience relevant to the BFN Monitoring of Neutron-Absorbing Materials Other Than Boraflex Program identified a 2009 Condition Report, NRC Information Notice 2009-26, "Degradation of Neutron-Absorbing Materials in the Spent Fuel Pool." This Condition Report resulted in the development of the corporate level procedure for the Spent Fuel Pool Neutron Absorber Material Monitoring Program that is currently utilized.

   This example demonstrates that the external operating experience program is used to improve the BFN Monitoring of Neutron-Absorbing Materials Other Than Boraflex program, assuring that these components will be able to continue to perform their intended functions during the subsequent period of extended operation.

Conclusion

The new Monitoring of Neutron-Absorbing Materials other than Boraflex program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.27 Buried and Underground Piping and Tanks

Program Description

The BFN Buried and Underground Piping and Tanks program is an existing aging management program that manages the aging effects associated with the external surfaces of buried and underground piping such as loss of material and cracking. It addresses buried and underground piping composed of any material, including metallic materials, that are within the scope of SLR in the Condensate Demineralized Water System, the Residual Heat Removal System, the Raw Service Water System, the High Pressure Fire Protection System, the Condenser Circulating Water System, the Containment System, the Standby Gas Treatment System, the Emergency Equipment Cooling Water System, the Radwaste System, the Containment Atmosphere Dilution System, and the Hardened Containment Venting System. The program also manages loss of material due to corrosion of piping system bolting within the scope of this program. BFN does not have any buried or underground polymeric or cementitious piping, and there are no buried or underground tanks within the scope of this program. In addition, BFN does not have any underground copper alloy materials within the scope of the program.

The program manages aging through preventive, mitigative, inspection, and performance monitoring activities. The BFN Buried and Underground Piping and Tanks program includes (a) preventive actions to mitigate degradation (e.g., external coatings or wrappings and quality of backfill), (b) condition monitoring (inspections) (e.g., nondestructive evaluation of pipe wall thickness, and visual inspections of the external surfaces and coatings/wraps of piping and components), and (c) performance monitoring activities (i.e., performance monitoring of fire mains) to provide early warning of system leakage.

Periodic visual inspections of external surfaces of buried components are performed to check for evidence of coating/wrapping damage, loss of material, and cracking. Periodic inspection of external surfaces of underground components is also performed to check for evidence of loss of material and cracking. The number of inspections for each 10-year inspection period, commencing within 10 years prior to the subsequent period of extended operation is based on the effectiveness of the preventive and mitigative actions. Cathodic protection is not utilized at BFN.

The selection of locations of these inspections will be based on factors including site OE, high-risk ranking, and results from soil analysis combined with results from pipe-to-soil surveys (soil corrosiveness of the environment in which the buried pipe to be inspected exists). Opportunistic visual inspections are also conducted for in-scope piping whenever they become accessible. Soil testing will be conducted in conjunction with the periodic direct inspections of buried piping. These inspections and tests will begin within 10 years before the subsequent period of extended operation and at least every 10 years during the subsequent period of extended operation.

Inspections will be 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 intended function when the material loss rate is extrapolated to the end of the subsequent period of extended operation, an increase in the sample size will be conducted. Degraded conditions such as loss of material, damaged coatings, or non-conforming backfill are evaluated under the Corrective Action Program.

Soil conditions at BFN have been evaluated and the soil was determined to be Moderately Corrosive (based on EPRI data). It was found to have moderate to high resistivity, and basic to near neutral pH. This is based on soil samples taken in 2009 and 2023. The GALL-SLR defines nonaggressive groundwater and soil as having pH > 5.5, chlorides < 500 ppm, and sulfates <1,500 ppm. Based on the GALL-SLR definition, the soil at BFN is nonaggressive.

Aging management of the buried High Pressure Fire Protection System piping will be accomplished through periodic flow testing of fire mains in accordance with NFPA 25.

This program does not address loss of material due to selective leaching. The Selective Leaching program (B.2.1.21) is used to manage loss of material due to selective leaching of susceptible materials.

The Buried and Underground Piping and Tanks aging management program will be enhanced as described below to provide reasonable assurance that in-scope buried piping and components constructed of steel, stainless steel, and copper alloy will perform their intended function during the subsequent period of extended operation.

NUREG-2191 Consistency

The enhanced Buried and Underground Piping and Tanks aging management program will be consistent with the 10 elements of aging management program XI.M41, Buried and Underground Piping and Tanks, specified in NUREG-2191, with the following exceptions.

Exceptions to NUREG-2191

1. Cathodic Protection Exception for Buried Steel Piping

   BFN was originally constructed without a cathodic protection system for steel buried piping. The approximate amount of buried steel piping involved is:

   - Emergency Equipment Cooling Water System - 3,497ft
   - Residual Heat Removal Service Water System - 14,097ft
   - Radwaste System - 2,879ft
   - Standby Gas Treatment System - 1,190ft
   - Condenser Circulating Water System - 13,311ft
   - Containment Atmosphere Dilution System - 846ft

   A study recently performed has concluded that installation of a cathodic protection system would be impractical and not very effective. Therefore, this exception to the preventive action recommended by NUREG-2191 is being taken. NUREG-2191 AMP XI.M41Section 2.g.iv. states that failure to provide cathodic protection may be acceptable if justified in the SLRA.

   This exception is justified based on the following:

   - Installation of a cathodic protection system is impractical. Operation of a cathodic protection system would likely not be very effective.
   - Plant-specific Operating Experience is acceptable based on a review conducted in accordance with NUREG-2191 AMP XI.M41 Section 2.g.iv.
   - BFN in-scope buried steel piping has a robust multilayer coating system that provides additional exterior protection which, at the time of plant construction, was intended for use where extraordinary soil conditions existed, or on such special construction as submarine lines or river crossings.
   - BFN has performed soil sampling to evaluate soil parameters including pH, soil composition, resistivity, and others to determine overall soil corrosivity. This information along with site operating experience and BPWORKS™ High Risk Ranking are used to select direct-inspection locations in accordance with NUREG-2191 AMP XI.M41 Section 4.d.
   - The existing program will be enhanced to be consistent with NUREG-2191 AMP XI.M41 Buried and Underground Piping and Tanks Aging Management Program, with exceptions.

   Program Elements Affected: Preventive Actions (Element 2), Parameters Monitored or Inspected (Element 3), Monitoring and Trending (Element 5), Acceptance Criteria (Element 6), Corrective Actions (Element 7)

   Justification for Exception 1

   Installation of a cathodic protection system is impractical. Operation of a cathodic protection system would likely not be very effective.

   BFN was originally constructed without a cathodic protection system for steel buried piping. TVA practice at the time was to depend on “coatings, painting, and proper selection of material for corrosion protection rather than using cathodic protection.” Cathodic protection was used only when needed to resolve a specific problem. This policy was documented by the TVA Cathodic Protection Task Force. Also, no time-based analysis for the design of the BFN steel buried piping thickness was found in the design basis documents. It is assumed that because of the shallow bedrock at the site (The bedrock depth at BFN shows bedrock present 27 to 64 feet below grade), a typical deep bed anode system utilized in the industry at that time, would not be very effective. Instead, a multilayer coating system, which at the time of plant construction would have been suitable for submarine or river crossing applications per AWWA C203-66, was selected to provide the defense-in-depth protection that a typical coating system with cathodic protection may provide.

In 2021, an evaluation was performed to understand potential cathodic protection systems for BFN. The evaluation considered an impressed current system where the ground grid is assumed as the cathode bonding the pipes electrically. Impressed current systems are typically recommended to be used for power plant applications because of the large current requirements for building foundation steel and grounding cable.

The scope of the evaluation was to protect all buried metallic piping at BFN. There were three types of cathodic protection systems considered: deep anode bed, remote shallow bed, and distributed anode bed.

- Deep Anode Bed Design

  In a deep bed system, the anodes are inserted into 8-to-10-inch diameter drilled holes which are between 200 to 600 feet deep. The major advantage of this system is that the anode beds may be in accessible areas outside the protected area and away from congested areas with risk of damage from digging operations. Significant presence of bedrock between ground level and the maximum hole depth can make this type of anode bed difficult to install or ineffective for cathodic protection. Cathodic protection by impressed current may not be possible if bedrock functions as a barrier to the current between the anodes and the protected buried piping. The bedrock depth at BFN shows bedrock present 27 to 64 feet below grade which makes deep anode beds unlikely to be effective for cathodic protection.

- Remote Shallow Bed Design

  A remote anode bed system would have anodes buried at a shallow depth but at locations which are remote from plant piping. A minimum distance of 500 feet should be maintained between each remote anode bed and the nearest buried piping to avoid overprotection of the nearest piping. This represents a 500-foot offset from the nearest plant buried piping. Most of the buried piping is near the plant powerhouse and south. Much of this piping would be shielded from protective current by building foundations or would receive insufficient current due to most current finding ground items nearer to the anode beds. In addition to shielding, there is the likely possibility that copper grounds would conduct most of the cathodic protection current before reaching the piping.

- Distributed Anode Bed Design

  A third cathodic protection design considered was the distributed anode bed system. A distributed bed anode system could be composed of 10 to 20 anode beds throughout the site and nearer to the buried piping targeted for protection.

  The specific issue with BFN implementing this design is the arrangement of the targeted plant piping, which is between the plant and the river/canal, and in a location congested with piping from the Residual Heat Removal Service Water System, the Emergency Equipment Cooling Water System, the High Pressure Fire Protection System, the Raw Water System, and other buried commodities. These lines are “nested” in some locations with many lines near each other and some routed perpendicular to each other.

Additionally, there are other barriers such as buildings and paved areas that would make proper locations of the required distributed anode bed very difficult. Considering the total excavations required to make welded connections for test stations, rectifier connections, hundred or more anode holes, excavations would not be recommended given the proximity to high-risk piping and the real possibility of damaging the piping or coating. Minimizing excavations with directional drilling methods is not recommended since it is just as likely to damage pipe or coatings.

True linear anodes would not be an option since it requires excavating the entire length of pipe and would be best suited for new pipe installations.

Overall, the evaluation concluded that installing a cathodic protection system for the in-scope buried steel piping was not recommended due to the high expected cost, uncertain effectiveness, and risk to existing buried commodities.

Therefore, installing a cathodic protection system at BFN would be impractical and not very effective primarily due to factors such as relatively shallow bedrock, and the piping layout being congested and shielded by buildings. Since BFN was not designed with cathodic protection, the assumption that all the piping is electrically continuous (bonded to the same copper grounding grid) is unverified. However, since the BFN High Pressure Fire Protection System piping was constructed with pipe segments requiring gasketed connection without bonding straps, applying cathodic protection to these areas would not provide protection to the pipe and could create a stray current situation that would accelerate the corrosion rate more than the current situation with no cathodic protection.

Plant Specific Operating Experience is Acceptable.

BFN reviewed opportunistic and planned buried piping inspections from a file structure maintained by the BFN Buried Piping Engineer which were conducted between 2009 and 2023. There were 98 inspections conducted, consisting of various buried piping materials and both coated and uncoated piping. Coating systems were both manufacturer (factory) applied coating systems and field applied coating systems. These inspections were conducted on both in-scope and not-in-scope systems. Four of the inspections reviewed were associated with buried steel piping with a muti-layered coating system that meets the guidance of AWWA C203-66, Section A1.5. These inspections showed the coatings were in excellent condition. These inspections were conducted on the Residual Heat Removal Service Water system, the Emergency Equipment Cooling Water system, the Primary Containment Ventilation system, and the Standby Gas Treatment system. Four other inspections of piping associated with the non-safety-related cooling towers, not in-scope for License Renewal, and coated with a factory epoxy coating system (not the multi-layered coating system of in-scope buried steel piping). These inspections identified degradation of the coating. Although corrosion was identified on these cooling tower-related pipes with the degraded epoxy coating, no piping failures occurred. No other failures of coatings (factory or field applied) were identified during this review.

Keyword searches of the condition reports for the period January 1, 2011 to September 1, 2023 were conducted. Based on this review, it is concluded that no degraded conditions have occurred at BFN that would have resulted in the applicable acceptance criteria of NUREG-2191 XI.M41 not being satisfied. Specifically, based on review of BFN-specific operating experience, no leaks in the subject buried piping due to external corrosion have been observed and no significant buried piping coating degradation has been observed. In addition, this review of BFN operating experience did not identify any failures associated with field applied coatings.

BFN Preventative Actions - Robust Coating System

The steel pipe is coated in accordance with American Water Works Association standard, AWWA C203-66, Section A1.5 - Coal-Tar Enamel, Fibrous-Glass Mat, and Bonded Asbestos-Felt Wrap. This type of additional exterior protection was intended, at the time of BFN construction, for use where extraordinary soil conditions existed, or on such special construction as submarine lines or river crossings. This multilayer coating system provides the defense-in-depth protection that a typical coating system with cathodic protection may provide.

The construction of this exterior protection involves six shop applied steps for purchased pipe lengths:

1. Primer (0.0025 in, +/- 0.0005 in)
2. Coal-tar enamel (3/32 in, +/- 1/32 in thick)
3. Fibrous-glass mat (0.018 in)
4. Coal-tar enamel (1/32 in minimum)
5. Bonded asbestos felt (12-15 lbs per 100 sqft)
6. Whitewash or kraft paper

The primer is a fast-drying synthetic primer which consists of chlorinated rubber, synthetic plasticizer, and solvents to produce a liquid coating that is readily applied cold by brushing or spraying. The primer provides a suitable and effective bond between the metal and the coal-tar enamel. The primer has a minimal tendency to produce bubbles during application, which minimizes the chance of the coating becoming disbonded from the pipe.

The coal-tar enamel used at BFN is AWWA coal-tar enamel, normal type (not cold-temperature type). It is composed of a specially processed coal-tar pitch combined with an inert mineral filler. The enamel does not contain asphalt.

The fibrous-glass mat is a thin, flexible, uniform mat, composed of glass fibers in an open porous structure, bonded together with a thermosetting resin which is compatible with the hot coal-tar enamel. No disbonding of individual glass fibers during or following the embedding process was permitted. The fibrous-glass mat was applied so not to cause bubbling under the conditions of application. The mat was sufficiently porous to be embedded in the hot coal-tar enamel as it is applied to the exterior of the pipe. The mat is approximately 18 mils in thickness.

The asbestos-coal-tar-saturated felt wrap is composed of asbestos felt (no less than 85% asbestos with a suitable binder) which is then saturated in distilled coal tar to produce the finished felt. The required characteristics include a visually defect-free surface, and not sticky at 32-100°F such that it will not tear when unrolled. The breaking strength of the asbestos wrap is not less than 25lb with the fiber grain, and not less than 10lb across the fiber grain (test method - ASTM D146-65). It can be bent over a 1-in. mandrel at 77°F with no cracking.

The additional layer of bonded felt wrap provides an added layer of protection for the coal tar enamel against soil stresses preventing creep and cold flow.

Table 1 of NACE SP0169-2007 cites the latest revision for AWWA C203 as an available reference for coal tar generic coating system use. The only significant difference between American Water Works Association standard, AWWA C203-66, Section A1.5 and the 2008 edition Section 4.7.2.1, is the use of a glass fiber outerwrap instead of the original bonded asbestos felt. This changed in the 1997 edition to move away from specifying materials that contain asbestos. Either wrap system is effective, therefore the BFN coating system is in accordance with Table 1 of NACE SP0169-2007.

Field applied coating materials at BFN are in compliance with AWWA C203-08. Application of field applied coatings is in compliance with AWWA C203-08. In addition, BFN design documents specify that after field repair of coating, checks for holidays were performed by either the ring or chain type electrode method using not less than 10,000 volts and that any faults detected were repaired. While full compliance with AWWA C203-08 could not be confirmed, the ability of the field applied coating to perform its intended function is demonstrated based in the results of BFN-specific operating experience. BFN reviewed opportunistic and planned buried piping inspections conducted since 2009. Based on this review, BFN has concluded that plant-specific operating experience is acceptable, i.e., there were no leaks in the subject buried piping due to external corrosion and no significant coating degradation was observed. In addition, this review of BFN operating experience did not identify any failures associated with field applied coatings. As a result, it is concluded that BFN field applied coatings are considered to be adequate for providing protection of associated buried piping components during the subsequent period of extended operation. To provide assurance that field applied coatings will continue to perform their intend function during the period of subsequent period of extended operation, enhancements are provided to ensure compliance with Table 1 of NACE SP0169-2007 for new and replacement field applied coating and to ensure direct inspections include fittings (e.g., elbows, tees, etc.) to capture the factory applied to field applied coating interfaces and the associated field applied coatings used at these locations.

BFN Preventative Actions - Backfill and Soil Characteristics and Periodic Inspections

<u>Backfill</u>

Preventive actions included in NUREG-2191 AMP XI.M41 consider that backfill located within 6 inches of the component that meets ASTM D 448-08 size number 67 meets the objectives of NACE SP0169-2007 and NACE RP0285-2002. ASTM D 448-08 indicates that size number 67 corresponds to a bounding value for backfill particles within 6 inches of the component to be no larger than 3/4 inch (nominal size). BFN specifications and design output require sand, clay, and/or rock-free earth backfill be used for buried piping included in the scope of the Buried and Underground Piping and Tanks AMP. However, while the definitions of sand and clay meet this size criteria, TVA General Engineering Specification G-9 allows for earthfill particles to be up to 3 inches. This is an exception to the guidance of NUREG-2191 AMP XI.M41 Section 2.f for meeting the objectives of NACE SP0169-2007. BFN operating experience demonstrates that surveys/tests (i.e., UPTI Inspection Checklist/NPG-SPP 09.15) are capable of detecting and identifying degraded conditions that would pertain to backfill. If found, degraded conditions are entered into the Corrective Action Program and then addressed. If the backfill does not meet acceptance criteria, the degraded condition is evaluated or repaired. BFN has shown no sign of damage done to buried piping due to backfill characteristics. Enhancements are provided to require that new and replacement backfill meet the guidance of NACE SP0169-2007 Section 5.2.3. In addition, backfill quality will be demonstrated in the subsequent period of extended operation by examining the backfill while conducting the inspections described in the associated enhancement and by review of plant records.

<u>Moderately corrosive soil</u>

Soil sampling is performed to evaluate corrosiveness of the environment in which the buried pipe exists. This information along with site operating experience and BPWORKS™ High Risk

Ranking are utilized to develop direct inspection prioritization to assess effectiveness of the coating system.

BFN has determined that the site-specific soils are moderately corrosive as specified by Electric Power Research Institute EPRI Report 3002005294, “Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants,” Table 9-4, “Soil Corrosivity Index from BPWORKS.” This is based on soil samples taken in 2009 and 2023, as described below. All soil samples were less than 10 points on the EPRI Soil Index.

The following text and Tables provide the details on soil samples performed in 2009 and 2023. The location ranking in the corrosion potential tables is used as an input to prioritize excavations and inspections.

2009 Soil Samples:

A soil analysis was performed, along with Area Potential Earth Current (APEC) survey and Close Interval Survey (CIS) on thirteen samples. Eleven samples were taken in the protected area, and two more were taken near the mechanical draft cooling towers. Site selection considered the following:

- Locations representative of engineered and compacted backfill; Locations representative of native geology around the cooling towers and Administration Buildings; Accessible locations (i.e., none paved) near highly congested piping locations near Safety Related piping.

2009 Summary of Soil Sample Results

Sample Location ID	Resistivity (as received ohm-cm)	Native Potential (-mV)	pH	Cl (ppm)	Na (ppm)	Ca (ppm)	K (ppm)	SO4 (ppm)	% Gravel	% Sand	% Silt	% Clay	% Water	Corrosion Rate (mpy)	Corrosion Rate at Boundary Condition (mpy)
BROWNS FERRY 1	3,540	502	6.6	58	20	137	11	83	3	30	10	57	26.8	7.5	
BROWNS FERRY 2	23,200	466	7.8	4	4	94	6	29	62	31	3	4	6.6	67.1	16.7
BROWNS FERRY 3	8,400	414	7.4	2	6	70	9	88	4	25	20	51	16.4	16.5	
BROWNS FERRY 4	11,720	566	7.6	6	7	128	9	57	4	17	21	58	16.3	6.5	
BROWNS FERRY 5	25,200	461	7.6	5	6	124	10	68	2	46	20	32	13.4	6.8	
BROWNS FERRY 6	16,400	395	5.5	3	4	44	8	84	4	40	12	44	25.5	17.3	
BROWNS FERRY 7	22,800	473	5.3	43	5	32	10	0	1	43	9	47	22.8	5.5	
BROWNS FERRY 8	7,840	521	7.2	57	11	119	15	79	3	26	22	49	17.4	6.8	
BROWNS FERRY 9	27,600	498	7.2	5	15	220	10	190	13	37	29	21	10.6	7.2	
BROWNS FERRY 10	9,200	495	7.4	1	7	40	6	66	0	27	23	50	15.4	8.5	
BROWNS FERRY 11	16,000	541	7.6	4	4	158	8	111	12	52	14	22	15.8	6.0	
BROWNS FERRY 12	6,640	835	7.4	3	9	43	5	40	0	9	33	58	21.0	4.5	
BROWNS FERRY 13	5,120	835	7.3	2	6	43	10	47	0	27	21	52	20.5	2.7	

Note: numbers highlighted in red are values greater than the upper boundary conditions; numbers highlighted in yellow are less than the lower boundary conditions. The number highlighted in tan (16.7), indicated the value is outside of the boundary conditions for the Structural Integrity Associates calculation of corrosion rate and should not be considered valid.

2023 Soil Samples:

A comprehensive soil analysis was conducted that incorporated high-risk in-scope piping locations and accessibility close to the target piping. Eight sample locations were selected. Corrosion potentials were recorded at each of the soil sample locations. In addition, 48 total native potential measurements were recorded as close interval survey (CIS).

2023 Summary of Soil Sample Results

Sample ID	Resistivity (received ohm-cm)	Native Potential (-mv)	pH	Cl (ppm)	NA (ppm)	Ca (ppm)	K (ppm)	Mg (ppm)	SO4 (ppm)	% Gravel	% Sand	% Silt	% Clay	% Water	LPR Corrosion Rate (mpy)
1-2	4700	327	8.17	2.74	3.01	87.7	46.4	2.47	22.1	34	42.7	6.39	16.9	17.6	15
1-3	4000	353	6.93	1.31	3.73	136	2.01	8.64	66.6	1.4	37.8	18.4	42.4	17.1	OVR
1-4	2600	514	8.06	3.15	5.16	116	4.84	4	26.3	18.3	38.4	7.42	35.8	24.1	17.5
1-5	3700	625	7.19	2.46	5.16	113	5.53	10.6	18.2	2.8	33	10.7	53.5	26.1	13.1
1-6	6800	634	7.88	1.23	0.854	91.7	3.13	8.13	13.3	3.5	59.3	10.6	26.6	19.2	0.34
1-8	3800	245	7.86	2.25	13.3	98.8	2.19	4.19	38.5	2.9	48	18.2	30.9	15.1	OVR
ALT 1	8300	367	7.01	1.12	2.2	40	12.1	2.33	72	0.2	46.9	17.6	35.3	14.8	25.5
ALT 4	4300	354	7.8	2.21	2.6	96.3	1.6	5.32	32.7	1.5	35.5	16.2	46.8	22.4	17.4

2009 and 2023 Soil Samples Comparison Summary:

A comparison of the 2009 and 2023 soil sample corrosivity values, using the EPRI index, does not show any adverse trends regarding corrosivity. The lower 2009 soil sample corrosivity value for samples #2 and #5 can be explained:

- Corrosivity value 4 for sample #2 had a high resistivity most likely related to the very high percentage of gravel in the sample. Also, location # 2 was more remote from the 2023 sample locations.
- Corrosivity value 5 for sample # 5, had a high resistivity value, and slightly higher pH.

The 11 remaining 2009 samples corrosivity values were in line with the 2023 values.

2009 Sample #	**EPRI Soil Index**	**Corrosivity**
#1	8	Moderately
#2	4	Moderately
#3	8	Moderately
#4	6	Moderately
#5	5	Moderately
#6	8	Moderately
#7	9	Moderately
#8	8	Moderately
#9	6	Moderately
#10	8	Moderately
#11	6	Moderately
#12	8	Moderately
#13	8	Moderately

2023 Sample #	**EPRI Soil Index**	**Corrosivity**
Alt1	7	Moderately
Alt4	7	Moderately
1-2	7	Moderately
1-3	8	Moderately
1-4	8	Moderately
1-5	8	Moderately
1-6	7	Moderately
1-8	7	Moderately

Corrosion potential measurements:

The following are summaries of corrosion potential measurements for the 2009 and 2023 soil sample locations.

2009 Sample #	EPRI Soil Index	Potentials (mV)	Corrosion Rate (mpy)	Location Rank
#1	8	502	7.5	4
#2	4	466	16.7	2
#3	8	414	16.5	1
#4	6	566	6.5	9
#5	5	461	6.8	10
#6	8	395	17.3	3
#7	9	473	5.5	6
#8	8	521	6.8	8
#9	6	498	7.2	11
#10	8	495	8.5	5
#11	6	541	6.0	7
#12	8	835	4.5	12
#13	8	835	2.7	13

2023 Sample #	EPRI Soil Index	Potential (mV)	LPR Corrosion Rate (mpy)	Location Rank
Alt1	7	367	25.5	3
Alt4	7	354	17.4	6
1-2	7	327	15	5
1-3	8	353	OVR	1
1-4	8	514	17.5	4
1-5	8	625	13.1	7
1-6	7	634	0.3	8
1-8	7	245	OVR	2

In addition, in the 2023 soil samples, 48 total native potential measurements were recorded as close interval survey (CIS). Fourteen locations were more negative than -0.550 volts, indicating that galvanic corrosion may not be very active at these sites. The remaining 33 locations showed potentials which varied between -0.168 volts to -0.550 volts. A more positive reading equates to a higher likelihood of galvanic corrosion of steel caused by dissimilar metals. The most positive potential of -0.168 volts (least negative) indicates an area strongly influenced by the copper grid.

Other Factors:

NUREG-2191 XI.S6 defines nonaggressive groundwater and soil as having pH > 5.5, chlorides < 500 ppm, and sulfates <1,500 ppm. Based on this definition, the soil at BFN is nonaggressive.

2023 Sample #	pH	Chlorides (ppm)	Sulfates (ppm)
ALT 1	7.01	1.12	72
ALT 4	7.8	2.21	32.7
1-2	8.17	2.74	22.1
1-3	6.93	1.31	66.6
1-4	8.06	3.15	26.3
1-5	7.19	2.46	18.2
1-6	7.88	1.23	13.3
1-8	7.86	2.25	38.5

SLR Periodic Inspection Plan

Given the reliance on coatings as a corrosion prevention method, the periodic inspection plan is a major part of the SLR Buried and Underground Piping and Tanks AMP for ensuring the aging effects of the external surfaces of buried and underground piping are properly managed during the subsequent period extended operation. A coating inspection strategy begins with selecting the locations for directly examining coating, piping, and backfill. Based on industry guidance, the BFN inspection locations are selected using: (1) site operating experience, (2) high risk ranking (BPWORKS™), and (3) indirect inspection results (soil analysis combined with pipe-to-soil surveys (close interval surveys (CIS), and area potential earth current surveys (APEC)).

From the 2009 soil sample APEC survey there were 6 recommended inspection locations that could possibly reflect localized areas of potential coating damage and active corrosion. It was recommended that these locations be excavated and directly inspected. There were also 6 locations recommended for excavation and direct examination based on the 8 soil samples from 2023 combined with the 48 total native potential measurements recorded as CIS. Table B.2.1.27-1 provides the dig locations prioritized primarily by soil sample analysis, APEC survey, and close interval survey (CIS) data and high consequence piping located near the sample locations. Figure B.2.1.27-1 shows the locations of these 12 dig sites.

Table B.2.1.27-1		
Dig #	**Nearest Sample Location**	**Driver**
Dig 1	1-3	A Soil corrosivity index of 8 with low Pipe-to-soil Potential of -353mV likely due to mixed metal influence of copper grounding, the LPR corrosion rate could not be acquired therefore unknown. The sample & dig location is in proximity to in-scope piping.
Dig 2	1-8	A Soil corrosivity index of 7 with a very low Pipe-to-soil Potential of 245mV likely due to mixed metal influence of copper grounding, the LPR corrosion rate could not be acquired therefore unknown. The sample and dig location is in proximity to in-scope piping.
Dig 3	Alt-1	A Soil corrosivity index of 7 with low Pipe-to-soil Potential of 367mV is likely due to mixed metal influence of copper grounding, and the relatively high LPR corrosion rate of 25.5 mpy. The sample and dig location is in proximity to in-scope piping.
Dig 4	#3	A Soil corrosivity index of 8 with low Pipe-to-soil Potential of -414mV is likely due to mixed metal influence of copper grounding, and the relatively high LPR corrosion rate of 16.5 mpy. The sample and dig location is in proximity to in-scope piping.
Dig 5	#1	A Soil corrosivity of 8 with Pipe-to-soil potential of -502mV Both CorrTech Close interval survey, and APEC survey indicate this an area of depressed potentials. The sample & dig location is in proximity to in-scope piping.
Dig 6	Area 1	The driver for this location is the CIS survey that documents the lowest Pipe-to-soil area potentials with a -168 mV, indicating mixed metal influence with the highest likelihood of galvanic corrosion due copper grounding or other metallic materials more noble than carbon steel. The sample (Area1 2023 CIS) & dig location is in proximity to in-scope piping. .
Dig 7	1-5	A Soil corrosivity of 8 and relatively high LPR rate of 13.1 mpy. The sample & dig location is in proximity to in-scope piping.
Dig 8	#10	A Soil corrosivity of 8, and the APEC survey with relatively low pipe-to-soil potential of 495mV. This dig location is in proximity to in-scope piping.
Dig 9	1-2	Soil corrosivity of 7, with CIS relatively low pipe-to-soil potential of 327mV likely due to mixed metal influence of copper grounding, and the relatively high LPR corrosion rate of 15.5 mpy. The sample & dig location is in proximity to in-scope piping.
Dig 10	#11, #6	The APEC survey and CIS pipe-to-soil potential of 541mV, with moderate LPR corrosion rate of 6. The dig location is in proximity to in-scope piping and is between SIA sample locations #6 and #11.
Dig 11	#9	SIA APEC Survey with a relatively low depressed pipe-to-soil potential of 498mV. This dig location is in proximity to in-scope piping. The sample & dig location is in proximity to in-scope piping.
Dig 12	#8	A Soil corrosivity of 8, relatively moderate LPR corrosion rate of 6.8 mpy. Pipe-to-soil potential of 521mV. The sample & dig location is in proximity to in-scope piping.

Figure B.2.1.27-1

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The planned periodic inspection schedule for the 12 recommended excavation locations is:

- There will be 6 inspections within the 10-year period prior to entry into the subsequent period extended operation, starting with the first 6 locations from Table B.2.1.27-1 and shown in Figure B.2.1.27-1 (Dig 1 through Dig 6). These inspections are in addition to any opportunistic inspections for this period.
- There will be 6 planned inspections for the first 10-year period of the subsequent period extended operation and will be based on the next 6 locations from Table B.2.1.27-1 and shown in Figure B.2.1.27-1 (Dig 7 through Dig 12), however these locations may be adjusted based on OE from the inspections of the first 6 locations above or industry OE. These inspections will be in addition to any opportunistic inspections for this period.
- Based on the results of these 12 excavations and any opportunistic inspections or applicable OE, 6 additional locations will be selected and inspected for the last 10-year period of the subsequent period extended operation.

The inspection requirements for these planned periodic inspections should include:

- Soil samples - Develop a sample plan that includes exact location coordinates, and the pipe segments in the area.
- Follow the guidance in the EPRI Report 3002018353, Revision 2, “Buried and Underground Piping and Tank Reference Guide.”
- Include in the inspection location a field applied coating section, for example fittings, or field weld locations and especially the interface with the mill applied coating.
- Coatings inspection by a qualified coatings inspector that is qualified in accordance with TVA Nuclear Power General Engineering Specification G-55, Technical and Programmatic Requirements for the Protective Coating Programs for TVA Nuclear Plants, which requires that (1) coating inspectors have sufficient knowledge to identify and describe coating failures using recognized industry standards and specifications (ASTM, NACE, and SSPC), (2) demonstrated knowledge of coatings obtained through training and/or plant experience, and (3) three years of coatings related experience with at least two years being nuclear experience.
- Evaluation of coating failures and non-conforming conditions by a Coatings Subject Matter Expert, who is qualified via the completion of industry recognized formal coatings training, such as the Electric Power Research Institute Comprehensive Coatings Course and the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course, or equivalent courses as identified in NUREG-2191 AMP XI.M41 Section 6.a.
- Pipe-to-Soil potential readings acquired at the excavation and adjacent to the excavation location. Alternate pipe-to-soil potential measurement locations should be selected where excavation locations are in the immediate vicinity of previously performed pipe-to-soil potential readings. Alternate pipe-to-soil potential measurement locations should be chosen to provide additional information applicable to selection of future excavation locations. A minimum of six pipe-to-soil potential readings should be acquired during each 10-year period (10 years prior to the subsequent period of extended operation and the first 10 years of the subsequent period of extended operation) and may be acquired anytime during the 10-year period of the scheduled dig (preferably prior to the actual excavation).
- Document As-found and As-left inspection results.

Enhancements to Existing Program

Without cathodic protection, the BFN preventive actions will be:

- Periodic direct buried piping inspections of in-scope piping.
- Soil corrosiveness of the environment in which the buried pipe exists along with site operating experience and BPWORKS™ High Risk Ranking are utilized to develop direct inspection prioritization to assess effectiveness of the coating system.
- Inspections will be documented and be performed with a qualified coatings inspector to evaluate the condition of the coating. These direct inspections include fittings (e.g., elbows, tees, etc.) to capture the factory applied to field applied coating interfaces.
- The quality of backfill in the vicinity of planned piping inspections will be evaluated.
- Soil testing will be conducted in conjunction with the periodic direct buried piping inspections.

2. Field Applied Coatings Exception

During BFN construction, field applied coatings were applied to steel pipe not mill coated, fittings of mill coated pipe and joints of mill coated pipe by wrapping them with coal tar protective coating in tape form. After construction, field applied coatings are also applied, during repair and replacement activities, by wrapping with the hot applied coal tar tape coating system. GALL-SLR AMP XI.M41 Element 2, Preventive Actions, indicates coatings, including field applied coatings, are to be in accordance with Table 1 of NACE SP0169-2007. Table 1 of NACE SP0169-2007 lists coal tar coatings systems that are in accordance with ANSI/ AWWA C203 (latest revision). Accordingly, a comparison between the BFN design input requirements and bill of materials associated with BFN field applied coal tar coatings (Tapecoat 20, a hot applied coal tar tape coating system) and AWWA C203-2008 (the closest version of AWWA C203 to the GALL-SLR AMP XI.M41 referenced NACE SP0169) was performed. The conclusion of this comparison is that the BFN field applied coating materials (coal tar tape and the associated primer), tape application and testing for holidays are consistent with AWWA C203-08 and therefore consistent with Table 1 of NACE SP0169-2007. However, documentation for some of the details associated with recommended practices for application (e.g., surface preparation) during original construction could not be located or the level of detail associated with recommended practices in design documentation was less than the level of detail specified in AWWA C203-08. Since compliance with these recommended practices cannot be demonstrated, an exception to meeting Table 1 of NACE SP0169-2007 is being taken. **Program Element Affected: Preventive Actions (Element 2)**

<u>Justification for Exception 2</u>

Field applied coating materials at BFN are in compliance with AWWA C203-08. Application of field applied coatings is in compliance with AWWA C203-08. In addition, BFN design documents specify that after field repair of coating, checks for holidays were performed by either the ring or chain type electrode method using not less than 10,000 volts and that any faults detected were repaired. While full compliance with AWWA C203-08 could not be confirmed, the ability of the field applied coating to perform its intended function is demonstrated based in the results of BFN-specific operating experience. BFN reviewed opportunistic and planned buried piping inspections conducted since 2009. Based on this review, BFN has concluded that plant-specific operating experience is acceptable, i.e., there were no leaks in the subject buried piping due to external corrosion and no significant coating degradation was observed. In addition, this review of BFN operating experience did not identify any failures associated with field applied coatings. As a result, it is concluded that BFN field applied coatings are considered to be adequate for providing protection of associated buried piping components during the subsequent period of extended operation. To provide assurance that field applied coatings will continue to perform their intend function during the period of subsequent period of extended operation, enhancements are provided below to ensure compliance with Table 1 of NACE SP0169-2007 for new and replacement field applied coating and to ensure direct inspections include fittings (e.g., elbows, tees, etc.) to capture the factory applied to field applied coating interfaces and the associated field applied coatings used at these locations.

3. Backfill Exception

   Backfill is to be consistent with SP0169-2007, Section 5.2.3. Preventive actions included in NUREG-2191 (GALL-SLR) AMP XI.M41 consider backfill that is located within 6 inches of the component that meets ASTM D 448-08 size number 67 (size number 10 for polymeric materials) to meet the objectives of NACE SP016-2007. As BFN does not have polymeric materials in-scope for the Buried and Underground Piping and Tanks aging management program, only the size criterion of Size 67 applies. Regardless, ASTM D 448-08 indicates size numbers 67 and 10 give the bounding values for backfill particles within 6 inches of the component to be no larger than 3/4 inch (nominal size). BFN specifications and design output require sand, clay, and/or rock-free earth backfill be used for buried piping included in the scope of the Buried and Underground Piping and Tanks aging management program. While the definitions of sand and clay meet the size criteria established in GALL-SLR AMP XI.M41, TVA General Engineering Specification, G-9, allows for earthfill particles to be up to 3 inches. This is an exception to meeting the objectives of NACE SP016-2007. **Program Element Affected: Preventive Actions (Element 2)**

   Justification for Exception 3

   This exception is determined to be acceptable because operating experience demonstrates that surveys/tests (i.e., UPTI Inspection Checklist/NPG-SPP 09.15) are capable of detecting and identifying degraded conditions that would pertain to backfill. If found, degraded conditions are entered into the Corrective Action Program and then addressed. If the backfill does not meet acceptance criteria, the degraded condition is evaluated or repaired. BFN has shown no sign of damage done to buried piping due to backfill characteristics. Enhancements are provided below to require that new and replacement backfill meet the guidance of NACE SP-0169-2007 Section 5.2.3, and to require that backfill quality be demonstrated during the subsequent period of extended operation by examining the backfill while conducting the inspections of buried piping and by review of plant records.

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Revise implementing procedures to explicitly include the Condensate Demineralized Water System and the Radwaste System within the scope of the SLR Buried and Underground Piping and Tanks Aging Management Program.

   Program Element Affected: Element 1 - Scope of Program

2. Revise implementing procedures to require that the inspections of buried and underground piping be conducted in accordance with the below Table, with the inspections evenly distributed among the three BFN units, and include inspection of fittings (e.g., elbows, tees, etc.) to capture factory applied to field applied coating interfaces and the associated field applied coatings used at these locations. They will further require that the planned inspections of buried and underground piping and the associated field applied coatings used at these

locations be conducted, as a minimum, by visual examination of the external surfaces of pipe or coatings.

Material	Environment	Number of Inspections	Notes
Steel	Soil/Buried	6	Category E - 6 inspections
Steel	Concrete	2	The concrete will be inspected for cracking, which could indicate piping degradation
Stainless Steel	Soil	2	None
Stainless Steel	Concrete	2	The concrete will be inspected for cracking, which could indicate piping degradation

There will be 6 inspections within the 10-year period prior to entry into the subsequent period extended operation, starting with the first 6 locations from Figure B.2.1.27-1 (Dig 1 through Dig 6). These inspections are in addition to any opportunistic inspections for this period. There will be 6 planned inspections for the first 10-year period of the subsequent period extended operation and will be based on the next 6 locations from Figure B.2.1.27-1 (Dig 7 through Dig 12), however these locations may be adjusted based on OE from the inspections of the first 6 locations above or industry OE. These inspections will be in addition to any opportunistic inspections for this period. And then, based on the results of these 12 excavations and any opportunistic inspections or applicable OE, 6 additional locations will be selected and inspected for the last 10-year period of the subsequent period extended operation.

Program Elements Affected: Element 2 - Preventive Actions, Element 4 - Detection of Aging Effects

3. Revise implementing procedures to require that soil testing using the guidance in the EPRI Report 3002018353, Revision 2, “Buried and Underground Piping and Tank Reference Guide,” be conducted in conjunction with the periodic direct inspections of buried piping.

   Program Element Affected: Element 2 - Preventive Actions

4. Revise implementing procedures to require that pipe inspection locations be determined based on factors including site OE, high-risk ranking (BPWORKS™), and indirect inspection results (soil analyses, close-interval surveys, and area potential earth current surveys), combined with results from pipe-to-soil potential surveys. Consideration is also given to characteristics such as coating type (i.e., material type), coating condition, backfill characteristics, soil resistivity, pipe contents, and pipe function.

   Program Elements Affected: Element 2 - Preventive Actions, Element 4 - Detection of Aging Effects

5. Revise implementing procedures to require that opportunistic inspections be conducted for in-scope piping whenever they become accessible.

   Program Elements Affected: Element 2 - Preventive Actions, Element 4 - Detection of Aging Effects

6. Revise implementing procedures to require that inspections in addition to the Table provided in Program Enhancement Number 2 be added, if appropriate, in response to plant-specific OE.

   Program Elements Affected: Element 2 - Preventive Actions, Element 4 - Detection of Aging Effects

7. Revise implementing procedures to require that inspections be documented (including as-found and as-left inspection results).

   Program Elements Affected: Element 2 - Preventive Actions, Element 4 - Detection of Aging Effects

8. Revise implementing procedures to require that inspections be performed by a qualified coatings inspector for evaluation of the condition of the coating. The coatings inspector will be qualified in accordance with TVA Nuclear Power General Engineering Specification G-55, Technical and Programmatic Requirements for the Protective Coating Program for TVA Nuclear Plants. Evaluation of coating failures and non-conforming conditions will be performed by a Coatings Subject Matter Expert, who is qualified via the completion of industry recognized formal coatings training, such as the EPRI Comprehensive Coatings Course and the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course, or equivalent courses as identified in NUREG-2191 AMP XI.M41 Section 6.a.

   Program Elements Affected: Element 2 - Preventive Actions, Element 4 - Detection of Aging Effects

9. Revise implementing procedures to require that pipe-to-soil potential readings are acquired at the excavation and adjacent to the excavation location to determine the potential for galvanic corrosion cells and to assess the effectiveness of the coating system. Alternate pipe-to-soil potential measurement locations should be selected where excavation locations are in the immediate vicinity of previously performed pipe-to-soil potential readings. Alternate pipe-to-soil potential measurement locations should be chosen to provide additional information applicable to selection of future excavation locations. A minimum of six pipe-to-soil potential readings should be acquired during each 10-year period (10 years prior to the subsequent period of extended operation and the first 10 years of the subsequent period of extended operation) and may be acquired anytime during the 10-year period of the scheduled dig (preferably prior to the actual excavation).

   Program Element Affected: Element 2 - Preventive Actions, Element 4 - Detection of Aging Effects

10. Revise implementing procedures to require that new and replacement field applied coating shall meet the guidance of Table 1 of NACE SP0169-2007.

    Program Element Affected: Element 2 - Preventive Actions

11. Revise implementing procedures to require that new and replacement backfill shall meet the guidance of NACE SP0169-2007 Section 5.2.3.

    Program Element Affected: Element 2 - Preventive Actions

12. Revise implementing procedures to require that backfill quality be demonstrated during the subsequent period extended operation by examining the backfill while conducting the inspections of buried piping and by review of plant records.

    Program Element Affected: Element 2 - Preventive Actions

13. Revise implementing procedures to revise the High Pressure Fire Protection System Ring Header Flow Test to (1) clarify that the test is being performed in accordance with Section 7.3 of NFPA 25 to satisfy the requirements of GALL-SLR AMP XI.M41 Element 2, Preventive

Actions, Section 2.g.iii, Element 3, Parameters Monitored or Inspected Section 3.f.i, and Element 4, Detection of Aging Effects Section 4.e.i, (2) the frequency of the test will be increased to require at least one test be performed in each 1-year period during the subsequent period extended operation, and (3) state that a reduction in available flow rate below the minimum required flow rate for the test will be used as an indication of possible fire main leakage.

Program Elements Affected: Element 2 - Preventive Actions, Element 3 - Parameters Monitored or Inspected, Element 4- Detection of Aging Effects

14. Revise implementing procedures to require that results of periodic flow testing of fire mains in accordance with NFPA 25, which do not satisfy the minimum required flow rate for the test, to be considered as indication of possible fire main leakage and entered into the Corrective Action Program for trending and resolution.

    Program Element Affected: Element 5 - Monitoring and Trending

15. Revise implementing procedures to state that flow test results for fire mains are acceptable if the results are in accordance with NFPA 25, Section 7.3.

    Program Element Affected: Element 6 - Acceptance Criteria

16. Revise implementing procedures to require that visual inspections of the external surfaces of controlled low strength material backfill be performed, in place of the visual inspections of the external surface condition of buried or underground piping and associated coatings, to detect potential cracks that could admit groundwater to the surface of the component. If alternatives to visual inspections are performed, they will be performed in accordance with NUREG-2191, Section XI.M41, Subsection 4.e.

    Program Element Affected: Element 3 - Parameters Monitored or Inspected

17. Revise implementing procedures to require that monitoring of the surface condition of coatings and wraps will be conducted for all excavations of buried pipe to determine if the coatings and wraps are intact, well adhered, and otherwise sound such that aging effects would not be expected for the base material of the component.

    Program Element Affected: Element 3 - Parameters Monitored or Inspected

18. Revise implementing procedures to require that monitoring of the surface condition of the buried and underground piping and components be conducted to detect indications of aging effects such as general, pitting, crevice, and microbiologically influenced corrosion (MIC), and that the surface condition of the component be examined when it is exposed, such as when coating damage is discovered.

    Program Element Affected: Element 3 - Parameters Monitored or Inspected

19. Revise implementing procedures to require that volumetric nondestructive examination techniques, or the use of pit depth gages or calipers for measuring wall thickness, will have been determined to be effective for the material, environment, and conditions (e.g., remote methods) to be examined, and will be confirmed to be capable of quantifying general wall thickness and the depth of pits.

    Program Element Affected: Element 3 - Parameters Monitored or Inspected

20. Revise implementing procedures to require that when coating damage is discovered and the pipe is found to be degraded, wall thickness measurements will be conducted to detect potential loss of material.

    Program Element Affected: Element 3 - Parameters Monitored or Inspected

21. Revise implementing procedures to require that any inspections performed to identify cracking due to stress corrosion cracking for stainless steel materials will use a method that has been determined to be capable of detecting cracking.

    Program Element Affected: Element 3 - Parameters Monitored or Inspected

22. Revise implementing procedures to clarify that coatings will not have to be removed that: (a) are intact, well-adhered, and otherwise sound for the remaining inspection interval; and (b) exhibit small blisters that are few in number and completely surrounded by sound coating bonded to the substrate.

    Program Element Affected: Element 3 - Parameters Monitored or Inspected

23. Revise implementing procedures to require that inspections for cracking be conducted on piping with degraded coating to assess the impact of cracks on the pressure boundary function of the component being visually inspected.

    Program Element Affected: Element 3 - Parameters Monitored or Inspected

24. Revise implementing procedures to require that BFN will take soil samples prior to planned excavations to confirm that the chemistry of the backfill is nonaggressive.

    Program Elements Affected: Element 3 - Parameters Monitored or Inspected, Element 4 - Detection of Aging Effects

25. Require that visual inspections be supplemented with surface and/or volumetric nondestructive testing if evidence of wall loss beyond minor surface scale is observed.

    Program Element Affected: Element 4 - Detection of Aging Effects

26. Revise implementing procedures to state that when conducting inspections of buried components embedded in concrete backfill or engineered flowable fill used as backfill, the backfill may be excavated and the pipe examined, or the soil around the backfill may be excavated and the cementitious material examined. Also state that the inspection will include excavation of the top surfaces and at least 50 percent of the side surface to visually inspect for cracks in the backfill that could admit groundwater to the external surfaces of the component. Additionally, require that when conducting inspection of backfill based on the number of inspections designated for that material type, 10 linear feet of the backfill be exposed for each inspection.

    Program Element Affected: Element 4 - Detection of Aging Effects

27. Revise implementing procedures to require that when plant-specific conditions result in transitioning to a higher number of inspections than originally planned at the beginning of a 10-year interval, the timing of the additional examinations will be based on the severity of the degradation identified and will be commensurate with the consequences of a leak or loss of function. However, in all cases, the expanded sample inspection will be completed within the 10-year interval in which the original inspection was conducted, or if this transition occurs in the latter half of the current 10-year interval, within 4 years after the end of the particular 10-year interval. Furthermore, these additional inspections conducted during the 4 years following the end of an inspection interval cannot also be credited towards the number of inspections required for the following 10-year interval. The number of inspections may be limited by the extent of piping subject to the observed degradation mechanism.

    Program Elements Affected: Element 4 - Detection of Aging Effects, Element 7 - Corrective Actions

28. Revise implementing procedures to require that when conducting inspection of backfill based on the number of inspections designated for that material type, 10 linear feet of the backfill will be exposed for each inspection.

    Program Element Affected: Element 4 - Detection of Aging Effects

29. Revise implementing procedures to require that when piping inspections are based on the number of inspections in lieu of percentage of piping length, 10 feet of piping will be exposed for each inspection. Additionally, when the percentage of inspections for a given material type results in an inspection quantity of less than 10 feet, then 10 feet of piping will be inspected. Also, if the entire run of piping of that material type is less than 10 feet in total length, then the entire run of piping will be inspected.

    Program Element Affected: Element 4 - Detection of Aging Effects

30. Revise implementing procedures to state that opportunistic examinations of non-leaking pipes may be credited toward examinations if the location selection criteria are met. The use of guided wave ultrasonic examinations may not be substituted for the required inspections.

    Program Element Affected: Element 4 - Detection of Aging Effects

31. Revise implementing procedures to require that where wall thickness measurements are conducted, the results will be trended when follow up examinations are conducted.

    Program Element Affected: Element 5 - Monitoring and Trending

32. Revise implementing procedures to explicitly require that, where practical, coating condition degradation will be projected until the next scheduled inspection, and that inspection/ examination 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.

    Program Element Affected: Element 5 - Monitoring and Trending

33. Revise implementing procedures, for coated piping, to require that there is either no evidence of coating degradation, or the type and extent of coating degradation is evaluated as insignificant by a Protective Coatings Subject Matter Expert who has completed industry recognized formal coatings training, such as the EPRI Comprehensive Coatings Course and the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course, or equivalent courses as identified in NUREG-2191 AMP XI.M41 Section 6.a.

    Program Element Affected: Element 6 - Acceptance Criteria

34. Revise implementing procedures to require that measured wall thickness projected to the end of the subsequent period of extended operation meets minimum wall thickness requirements.

    Program Element Affected: Element 6 - Acceptance Criteria

35. Revise implementing procedures to require that indications of cracking in metallic pipe be managed in accordance with the Corrective Action Program and require that indications of cracking in underground or buried in-scope piping be evaluated in accordance with applicable codes and plant-specific design criteria.

    Program Elements Affected: Element 6 - Acceptance Criteria, Element 7 - Corrective Actions

36. Revise implementing procedures to state that backfill is acceptable if the inspections do not reveal evidence that the backfill caused damage to the component's coatings or the surface of the component (if not coated).

    Program Element Affected: Element 6 - Acceptance Criteria

37. Revise implementing procedures to state that cracks in cementitious backfill that could admit groundwater to the surface of the component are not acceptable.

    Program Element Affected: Element 6 - Acceptance Criteria

38. Revise implementing procedures to require that where damage to the coating has been evaluated as significant and the damage was caused by nonconforming backfill, an extent of condition evaluation will be conducted to determine the extent of degraded backfill in the vicinity of the observed damage.

    Program Element Affected: Element 7 - Corrective Actions

39. Revise implementing procedures to require that coated or uncoated metallic piping that is found to show evidence of corrosion will have the remaining wall thickness in the affected area determined to ensure that the minimum wall thickness is maintained. This may include different values for large area minimum wall thickness and local area wall thickness. If the wall thickness extrapolated to the end of the subsequent period of extended operation meets minimum wall thickness requirements, recommendations for expansion of sample size will not apply.

    Program Element Affected: Element 7 - Corrective Actions

40. Revise implementing procedures to explicitly require that where the coatings, backfill, or the condition of exposed piping does not meet acceptance criteria, the degraded condition will be repaired, or the affected component will be replaced. In addition, where the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material is extrapolated to the end of the subsequent period of extended operation:
    - An expansion of sample size will be conducted.
    - The number of inspections within the affected piping categories will be doubled or increased by five, whichever is smaller.
    - If the acceptance criteria are not met in any of the expanded samples, an analysis will be conducted to determine the extent of condition and extent of cause.
    - The number of follow-on inspections will be determined based on the extent of condition and extent of cause.
    - The expansion of sample inspections may be halted in a piping system or portion of system that will be replaced within the 10-year interval in which the inspections were conducted or, if identified in the latter half of the current 10-year interval, within 4 years after the end of the 10-year interval.

    Program Element Affected: Element 7 - Corrective Actions

41. Require that the section of underground carbon steel piping (in an isolation valve pit) in the Hardened Containment Venting System which is not coated consistent with GALL SLR Element 2 for underground steel piping, will be coated in accordance with Table 1 of NACE SP0169-2007 prior to the subsequent period of extended operation.

    Program Element Affected: Element 2 - Preventive Actions

<u>Operating Experience</u>

The following examples of operating experience provide objective evidence that the Buried Piping and Tanks Inspection Program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation

1. In 2022, a program effectiveness review was performed for the Buried Piping and Tanks Inspection Program to verify that the intent of the existing aging management program activities to identify and correct, as warranted, age-related degradation of Buried Piping, is being effectively implemented in the initial license renewal period of extended operation. The program effectiveness review was comprised of a review of inspection implementation activities to date and pertinent issues in the Corrective Action Program, searching for identified age-related degradation of buried piping. Pre-period of extended operation, visual inspection results, and resulting issues in the Corrective Action Program were also reviewed. The reviews did not identify significant age-related degradation due to loss of coating of buried piping that would preclude it from performing its intended function.

   A Corporate Engineering assessment for the buried piping program was performed in 2015. The findings of this assessment were the following: No areas for improvement, four performance deficiencies and seven Learning Opportunities. Two of the performance deficiencies were applicable to BFN dealing with procedure revisions. Of the seven Learning Opportunities, there were five that included BFN. Two dealt with training issues, one Corporate procedure issue, one for corporate to create an OE tracking database and one for the sites to develop an Underground Piping and Tanks Inspection (UPTI) Program owner turnover checklist. There was also a QA audit performed in July, 2022. This audit reviewed several programs and included the Buried Piping Program. This audit found no issues with the Buried Piping Program.

   This operating experience provides objective evidence that the Buried Piping and Tanks Inspection Program aging management activities are being implemented to manage aging effects of in-scope buried piping. Continued implementation of the Buried Piping and Tanks Inspection Program will assure that components within the scope of the program will continue to perform their intended functions during the subsequent period of extended operation.

2. The Buried Piping and Tanks Inspection Program had an Initial License Renewal Commitment to perform an engineering evaluation to determine if sufficient buried pipe inspections had been conducted to draw a conclusion regarding the ability of the buried pipe coatings to protect the piping from degradation. In January 2022, a work order was initiated to perform the evaluation. This evaluation determined that sufficient inspections had been performed to draw a positive conclusion about buried piping coatings. However, during the effectiveness review, it was discovered that the evaluation lacked the proper critical thinking and results for that conclusion to be reached. A revised document that provided the proper critical thinking backed up by documented results (i.e., documented results on excavated piping) was performed via an Engineering Work Request (EWR). This condition was documented in the Corrective Action Program in a condition report in February 2023. The EWR was performed by a contracting firm and completed in May 2023. The EWR listed several completed work orders and inspections that revealed the coatings on buried piping have been able to protect the associated piping from degradation.

   This operating experience provides objective evidence that the Buried Piping and Tanks Inspection Program aging management activities are being implemented to manage aging effects of in-scope buried piping. Continued implementation of the Buried Piping and Tanks Inspection Program will assure that components within the scope of the program will continue to perform their intended functions during the subsequent period of extended operation.

3. A TVA fleet assessment was conducted on the Underground Piping and Tanks Program in September 2022. The assessment identified a gap in the procedure for the Underground Piping and Tanks Integrity Program. The gap was that the procedure contained License Renewal Commitment ties and references that were not accurate. The procedure revision should have clearly documented all current license renewal commitments and requirements

tied to the Buried Piping program. This was identified in a condition report. The procedure for the Underground Piping and Tanks Integrity Program was subsequently revised.

This operating experience provides objective evidence of the program being reviewed and changes are incorporated to ensure that all affected License Renewal Commitments piping systems will be listed under the controlling procedure to assure that components within the scope of the program will continue to perform their intended functions during the subsequent period of extended operation.

4. An Inspection of the excavated radwaste discharge piping associated with the cooling tower blowdown isolation valve was completed in September 2019. The results of the inspection were that the piping was greater than 87.5 percent nominal wall thickness and the pipe coatings were in good condition.

   This operating experience provides objective evidence that the continued implementation of the Buried Piping and Tanks Inspection Program will assure that components within the scope of the program will continue to perform their intended functions during the subsequent period of extended operation.

Conclusion

The enhanced Buried and Underground Piping and Tanks program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.28 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 aging management program is a new condition monitoring program that includes visual inspections of internal coatings/linings of cast iron, ductile iron, stainless steel and carbon steel piping, piping components, valve bodies, tanks, and heat exchangers exposed to raw water, treated water, air, and condensation. There are no piping or components with internal coatings/linings in the program scope that are exposed to closed-cycle cooling water, treated borated water, waste water, fuel oil, and lubricating oil. This program is not used to manage the integrity of coatings applied to external surfaces of piping or components.

The scope of the program is internal coatings/linings for in-scope piping, piping components, heat exchangers, and tanks exposed to raw water, treated water, air and condensation where loss of coating or lining integrity could prevent satisfactory accomplishment of any of the component's or downstream component's current licensing basis (CLB) intended functions

The in-scope systems managed by this program will be:

- High Pressure Fire Protection (Diesel Driven Pump) System
- Control Air System
- Service Air System
- Condensate/Demineralized Water System
- Residual Heat Removal Service Water System

The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program will include periodic visual inspections to verify the integrity of internal coatings designed to adhere to and protect the base metal. For tanks, and heat exchangers, all accessible surfaces are inspected. Piping inspections are sampling-based. Inspection intervals are established by a coating specialist qualified in accordance with an ASTM International standard endorsed in Regulatory Guide 1.54, Revision 2, “Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants.” However, inspection intervals will not exceed those specified in NUREG-2191, AMP XI.M42, Table XI.M42-1, “Inspection Intervals for Internal Coatings/Linings for Tanks, Piping, Piping Components, and Heat Exchangers, and Tanks.”

For non-cementitious materials, the training and qualification of individuals involved in coating/lining inspections and evaluating degraded conditions will be conducted in accordance with an ASTM International standard endorsed in Regulatory Guide 1.54, Revision 2, including NRC limitations associated with a particular standard, except for cementitious materials. For cementitious coatings/linings inspectors will have a minimum of five years of experience inspecting or testing concrete structures or cementitious coatings/linings or a degree in the civil/structural discipline and a minimum of one year of experience.

Inspection results that do not satisfy established acceptance criteria are entered into the BFN 10 CFR 50, Appendix B Corrective Action Program. The Corrective Action Program ensures that conditions adverse to quality are promptly corrected.

The program will be implemented through various station procedures and work activities. Inspections are performed for signs of coating failures and precursors to coating failures including peeling, delamination, blistering, cracking, flaking, chipping, rusting, and mechanical damage. Peeling and delamination is not acceptable. Blisters are evaluated by a coatings specialist, and should be limited to a few intact small blisters that are completely surrounded by sound material, and with size and frequency not increasing between inspections. Minor cracks in cementitious coatings are acceptable provided there is no evidence of debonding.

Coatings/linings that do not meet acceptance criteria are repaired, replaced, 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 encompass sound coating/lining material. These inspections, and subsequent repairs, replacements, or evaluations of internal coatings will provide reasonable assurance that in-scope components and downstream components will meet current licensing basis intended functions for the subsequent period of extended operation.

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

NUREG-2191 Consistency

The Internal Coatings/Linings for Piping, Piping Components, Heat Exchangers, and Tanks aging management program will be consistent with the 10 elements of aging management program XI.M42, Internal Coatings/Linings for Piping, Piping Components, Heat Exchangers, and Tanks, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the new BFN Internal Coatings/Linings for In-scope Piping, Piping Components, Heat Exchangers, and Tanks aging management program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. On January 28, 2011, the 2C Residual Heat Removal Heat Exchanger was opened and cleaned for Eddy Current testing and inspection under a Work Order (WO). The inspection revealed that the partition plate was corroded to the point of allowing a bypass flow. The corroded area covers approximately 75% across the length of the partition plate. WOs were initiated to apply an approved coating material onto the carbon steel surfaces in the Residual Heat Removal Service Water inlet and outlet water box of the Residual Heat Removal Heat Exchangers. These WOs were all completed within 4 years.

   This example provides objective evidence that inspections will be effective in identifying and managing aging effects.

2. On May 10, 2009, during a raw water inspection, corrosion was found present on the partition plate in 2D Residual Heat Removal Heat Exchanger. A WO was initiated to cut out and replace the partition plate. The WO was completed on October 17, 2013.

   This example provides objective evidence that inspections will be effective in identifying and managing aging effects.

3. On October 31, 2012, during the raw water inspection on the 1A Residual Heat Removal Heat Exchanger, significant corrosion was found on the bottom seam/weld of partition plate. The partition plate was corroded through for approximately 40-50% of the length of this seam/weld. A Condition Report was initiated to track and trend the degradation and a WO was initiated to replace the partition plate. The WO was completed on October 31, 2015.

   This example provides objective evidence that the BFN Corrective Action Program will be effective in ensuring that identified issues are monitored and corrected.

4. On September 23, 2020, the Residual Heat Removal Service Water System Engineer performed a Generic Letter 89-13 Raw Water Inspection on the 3C Residual Heat Removal Heat Exchanger. During this inspection, approximately 20% of the coating on the outlet side of the partition plate was found to have delaminated, and tubercles were growing on the exposed carbon steel surface. A coating report was generated and WOs were initiated and completed to disassemble, clean, inspect and repair the heat exchanger prior to returning it to service.

   This example provides objective evidence that the opportunistic inspections will be effective in identifying and managing aging effects.

Conclusion

The new Internal Coatings/Linings for Piping, Piping Components, Heat Exchangers, and Tanks program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.29 ASME Section XI, Subsection IWE

Program Description

The ASME Section XI, Subsection IWE aging management program is an existing condition monitoring program based on ASME Code and complies with the provisions of 10 CFR 50.55a. The program consists of periodic visual, surface, and volumetric examinations, where applicable, of metallic pressure-retaining components of steel containments for signs of degradation, damage, irregularities, and for coated areas distress of the underlying metal shell, and corrective actions. This program requires visual examinations of the accessible surfaces (base metal and welds) of the drywell, torus, vent lines, internal vent system, penetration assemblies and associated integral attachments. The program also requires examination of pressure-retaining bolting and the drywell interior slab moisture barrier. Acceptability of inaccessible areas of steel containment shell is evaluated when conditions found in accessible areas indicate the presence of, or could result in, flaws or degradation in inaccessible areas.

The program includes preventive actions that provide reasonable assurance that moisture levels associated with an accelerated corrosion rate do not exist in the exterior portion of the BWR Mark I steel containment drywell shell. The actions will consist of monitoring the sand bed drain line outlets for blockage and leakage during each outage when the refueling cavity is filled with water.

The program is also supplemented to include preventive actions to provide reasonable assurance that bolting integrity is maintained. The preventive actions emphasize proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of structural bolting.

This program also includes aging management for the potential loss of material due to corrosion in the inaccessible areas of the BWR Mark I steel containment, including periodic ultrasonic test examinations of Units 1, 2, and 3 drywell liner plate near the sand bed region. In addition, the program includes, 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 that is inaccessible from one side. Results are compared with prior recorded results in acceptance of components for continued service.

The program includes aging management of steel and stainless-steel surfaces and components such as the drywell shell and integral attachments, torus shaped pressure suppression chamber, suppression chamber integral attachments, containment penetrations including sleeves and bellows, containment hatches and airlocks, downcomers and bracing, moisture barriers, and pressure-retaining bolting for cracking, loss of leak tightness, loss of material, loss of preload, and loss of sealing.

The current program complies with ASME Section XI, Subsection IWE, 2013 Edition, supplemented with the applicable requirements of 10 CFR 50.55a. In accordance with 10 CFR 50.55a(g)(4), the ISI program is updated each successive 120-month inspection interval to comply with the requirements of the latest edition of the ASME Code specified 18 months before the start of the inspection interval. The ASME Code edition consistent with the provisions of 10 CFR 50.55a will be used during the subsequent period of extended operation.

The BFN primary containments are BWR Mark I metal containments. The scope of the ASME Section XI, Subsection IWE program is consistent with the scope identified in

Subsection IWE-1000 and includes the Class MC pressure-retaining components and their integral attachments including wetted surfaces of submerged areas of the pressure suppression chamber and vent system, containment pressure-retaining bolting, and metal containment surface areas, including welds and base metal.

The program utilizes inspections that detect degradation before loss of intended function. The ASME Code Section XI, Subsection IWE program implements the requirements of IWE by providing visual examinations (General Visual and VT 3) and augmented inspections (VT-1) for evidence of aging effects that could affect structural integrity or leak tightness of the primary containment. Areas subject to augmented inspection are subject to visual inspection (VT-1) and volumetric (ultrasonic) examination techniques as required by engineering per IWE-1240. The program addresses the E-A and E-C examination categories described in Table IWE-2500-1 and as approved per 10 CFR 50.55a. The frequency and scope of examinations specified is in accordance with 10 CFR 50.55a, and ASME Section XI, Subsection IWE 2400.

The program provides for periodic inspections for the presence of age-related degradation on all accessible surfaces of the containment on a scheduled basis. When examination results require an evaluation or the component is repaired and is found to be acceptable for continued service, the areas containing such flaws, degradation, or repair are reexamined during the next inspection period, in accordance with Examination Category E-C.

The acceptance criteria for the ASME Section XI, Subsection IWE program are in accordance with the requirements of the ASME Code, Subsections IWE- 3000 and IWE-3500.

Indications are evaluated and compared to acceptance standards. Unacceptable conditions are recorded and documented in accordance with the Corrective Action Program and supplemental examinations are performed in accordance with IWE-3200. Conditions which do not meet the acceptance criteria are accepted by an engineering evaluation or corrected by repair or replacement in accordance with IWE-3122.

Repairs and re-examinations, when required, are performed in accordance with IWA-4000 as required by IWE-3124 and the components are repaired or replaced to the extent necessary to meet the acceptance standards of IWE 3500. Component reexaminations are conducted in accordance with the requirements of IWA-2200 and the results are recorded to demonstrate that the repair meets the owner defined acceptance standards per IWE-3500.

NUREG-2191 Consistency

The enhanced ASME Section XI, Subsection IWE aging management program will be consistent with the 10 elements of aging management program XI.S1, ASME Section XI, Subsection IWE, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Include the following components within the scope of the program:
    - dissimilar metal welds
    - bellows

   Program Element Affected: Element 1 - Scope of Program

2. 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, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” dated August 2014, will be used.

   Program Element Affected: Element 2 - Preventive Actions

3. Revise implementing procedures to include monitoring of sand bed and refueling seal drains for water leakage on a weekly basis when the reactor cavity is filled with water.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

4. Revise implementing procedures to include periodic monitoring to ensure the sand bed drains are kept clear to prevent moisture levels associated with accelerated corrosion rates in the exterior portion of the BWR Mark I steel containment drywell shell.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

5. Revise implementing procedures to require a one-time volumetric examination of metal shell or liner surfaces that are inaccessible from one side, only if triggered by plant-specific operating experience. The trigger for this supplemental examination will be plant-specific occurrence or recurrence of measurable metal shell or liner corrosion (base metal material loss exceeding 10 percent 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 will consist 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 will be addressed in accordance with the applicable provisions of this aging management program. The sample size, locations, and any needed scope expansion (based on findings) for this one-time set of volumetric examinations will be determined on a plant-specific basis to demonstrate statistically with 95 percent confidence that 95 percent of the accessible portion of the containment liner is not experiencing corrosion degradation with greater than 10 percent loss of nominal thickness. Guidance provided in EPRI TR-107514 may be used for sampling considerations.

   Program Element Affected: Element 4 - Detection of Aging Effects

6. Revise implementing procedures to state the requirements of ASME Code Section XI, Subsection IWE and 10 CFR 50.55a are supplemented to perform surface examination (or other applicable technique) in addition to visual examinations, to detect cracking in stainless steel penetration sleeves, dissimilar metal welds, bellows, and steel components that are subject to cyclic loading but have no current licensing basis fatigue analysis. Containment integrated leak rate (Type A) tests and local leak rate (Type B) tests performed by the 10 CFR 50 Appendix J program (B.2.1.31) are credited for detection of cracking of dissimilar

metal weld penetrations and penetration bellows, respectively, in lieu of supplemental surface examinations.

Program Element Affected: Element 4 - Detection of Aging Effects

7. Revise implementing procedures to carry forward Commitment No. NCO040006088, Enhance ASME Section XI, Subsection IWE Program to perform a UT inspection of the sand bed area of the drywell liner of Units 1, 2, and 3. Subsequent periodic inspections will be performed on each unit prior to entry into the subsequent period of extended operation and at least once every 10 years thereafter.

   Program Element Affected: Element 4 - Detection of Aging Effects

8. Revise implementing procedures to include additional provisions to address identified degradation of weld pressure-retaining components that are subject to cyclic loading but do not have a fatigue analysis to undergo repair, rework, replacement, or justification for continued use by engineering evaluation.

   Program Element Affected: Element 6 - Acceptance Criteria

9. Revise implementing procedures to specify the additional ASME code subsections identified within IWE-3000 for addressing the following conditions:
   - Areas identified with damage or degradation that exceed acceptance standards require an engineering evaluation or require correction by repair or replacement, and
   - For the containment steel shell or liner, material loss locally exceeding 10 percent of the nominal containment wall thickness or material loss that is projected to locally exceed 10 percent of the nominal containment wall thickness before the next examination are documented.

   Program Element Affected: Element 6 - Acceptance Criteria

10. Revise implementing procedures to require a causal analysis for instances when sources of moisture cannot be identified in the inaccessible area on the exterior of the containment drywell shell.

    Program Element Affected: Element 7 - Corrective Action

11. Revise implementing procedures to state that if moisture has been detected or suspected in the inaccessible area on the exterior of the containment drywell shell or the source of moisture cannot be determined subsequent to causal analysis, then:
    - Any components that are identified in the future as a source of moisture, will be added to the scope of SLR and if applicable, an aging management review will be performed.
    - Pursuant to Subsection IWE-1240, identify in the inspection program affected drywell surfaces requiring augmented examination for the subsequent period of extended operation in accordance with Table IWE-2500-1, Examination Category E-C.
    - Conduct augmented inspections of the identified drywell surfaces using examination methods that are in accordance with Subsection IWE-2500.
    - Demonstrate, through use of augmented inspections performed in accordance with Subsection IWE, that corrosion is not occurring or that corrosion is progressing so slowly that the age-related degradation will not jeopardize the intended function of the drywell shell through the subsequent period of extended operation.

    Program Element Affected: Element 7 - Corrective Action

<u>Operating Experience</u>

The following examples of operating experience provide objective evidence that the ASME Section XI, Subsection IWE program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for the ASME Section XI Subsection IWE Program described in FSAR Section O.1.29. The purpose of the program effectiveness review was to verify that the existing aging management program activities, to identify and correct, as warranted, age-related degradation of components monitored by the Inspections of the ASME Section XI Subsection IWE Program, are being effectively implemented in the initial license renewal period of extended operation. The program effectiveness review was comprised of a review of inspection implementation activities to date and pertinent issues in the Corrective Action Program, searching for identified age-related degradation of components related to ASME Section XI Subsection IWE. The program manages the effects of aging on the BFN Units 1, 2, and 3 Steel Containment and integral attachments that are within the scope of 10 CFR 54.4, Requirements for Renewal of Operating License for Nuclear Power Plants. The review identified that inspections of components within the scope of the primary containment portion of the ISI Program are being performed in accordance with the extent and schedule described in ASME Section XI, Subsection IWE-2500 and the BFN ISI Program Plan. The review identified that inspections performed within the program are effective at identifying age related degradation of in-scope components before significant degradation has occurred. Age-related issues were evaluated in accordance with ASME Code Section XI requirements and corrective actions were taken to prevent further degradation in effective implementation of this aging management program. Inspection activities documented in ASME, Section XI, Owners Activity Reports, which are submitted to the NRC were reviewed. These reports document in-service examination results that were performed on components within the ASME Section XI boundary during the associated outage. These reports contain repair/replacement documentation for degradations identified. Details from these reports show that issues identified are being addressed in the Corrective Action Program. Corrective actions include evaluation of the acceptability of the issue found. These evaluations have three results:
    - Acceptability as is, the component is capable of fulfilling its intended function.
    - Acceptability as is, the component is capable of fulfilling its intended function. However increased inspection frequency is required.
    - The issue is unacceptable, and repairs are made to correct the issue.

   This operating experience provides objective evidence that the current ASME Section XI, Subsection IWE program is being effectively implemented to manage aging effects. Continued implementation of the ASME Section XI, Subsection IWE aging management program will assure that the components within the scope of the program will continue to perform their intended functions during the subsequent period of extended operation.

2. During the Unit 1 refueling outage in 2014, the Drywell Moisture Seal was inspected. Damaged gouged areas, with a length of 1/2 to 3 inches and a depth of 1/2 to 3/4 inches, were found at 8 locations. The condition was entered into the Corrective Action Program. The conditions were evaluated, and repairs were determined to be needed. Repairs were subsequently completed.

   During the Unit 2 refueling outage in 2017, the Suppression Pool Moisture Seal Coatings were inspected. Exterior coatings exhibited peeling in Bay 9, and pitting, gouges, and dents in Bays 2, 3, and 8. These inspection results were entered into the Corrective Action Program.

The conditions were evaluated; the pitting gouges and dents were determined to be acceptable, and repairs were determined to be needed to the moisture seal coating. Repairs to the moisture seal coating were subsequently completed. Re-inspection was completed with acceptable results. Additional inspections of Bays 2, 3, and 8 were scheduled and performed during refueling outages in 2019 and 2021 with acceptable results.

During the Unit 3 refueling outage in 2018, the Drywell Moisture Seal was inspected. Visual examination of the Drywell liner below the Moisture Seal, in areas excavated for repair revealed two gouges approximately 0.031 inches in depth, 0.125 inches in width, and 0.1875 inches in length. The condition was documented in the Corrective Action Program. The resulting engineering evaluation determined that the condition does not affect the structural integrity or leak tightness of the Drywell liner, since the depth of the indication did not exceed the minimum shell thickness acceptance criteria. The degradations were found to be acceptable with no repair required.

This example provides objective evidence that the ASME Section XI, Subsection IWE aging management examinations performed by qualified personnel are capable of detecting damage to in-scope components and other indications of possible age-related degradation, and that the moisture barrier degradation was repaired prior to the onset of corrosion to the containment shell. This example also demonstrates that deficiencies are entered into the Corrective Action Program and actions are taken to address deficiencies in accordance with ASME Code Section XI requirements.

3. In 2017, there was a self-assessment specific to the ASME Section XI, Containment Inservice Inspection program. The purpose was to assess compliance with regulations, industry guidelines or TVA commitments associated with the ASME Section XI Inservice Inspection, Containment Inservice Inspection and Augmented examination scope for the Unit 3 refueling outage 17. Learning opportunities were identified and documented in the Corrective Action Program, which resulted in changes to the ASME Section XI Containment Inservice Inspection Program Units 1, 2, and 3 procedures. Browns Ferry Nuclear 2020 License Renewal Self-Assessment documented in the Corrective Action Program. The purpose of the self-assessment was to review License Renewal commitments and documents implemented during period of extended operation. This assessment did not identify any deficiencies associated with the ASME Section XI Subsection IWE program.

   This example demonstrates that periodic self-assessments of the ASME Section XI, Subsection IWE aging management program have been performed to identify and correct program elements that need improvement to maintain the quality performance of the program.

4. BFN Units 1, 2, and 3 use the Mark I steel primary containment design. This design is subject to corrosion and generalized wasting at the sand bed region (SBR), as identified in NRC Generic Letter 87-05. The generic letter documented wall thinning at the SBR at Oyster Creek Generating Station that resulted from significant material wasting of the carbon steel plates from corrosion with potential to impair operability of containment.

   The BFN Units 1, 2, and 3 Mark I steel primary containment SBR consists of a transition region between the concrete pedestal that supports the drywell and the concrete walls surrounding the drywell. The SBR at BFN consists of a band, or ring, of sand around the exterior of the drywell shell that extends from elevation 548.79' to elevation 550.29'. The SBR is contained via the drywell liner on the inside, a 10-gage metal plate on the outside, and seals between the zone and drains at the base of the SBR. This region includes eight, 4", drain lines which are equally spaced around the circumference and open at the bottom of the SBR. The SBR drains provide a path to drain water that may inadvertently leak into the SBR. The sand-filled drain lines are embedded in concrete until they exit into the reactor building basement at approximately elevation 537' where a stainless-steel screen is installed to prevent the sand from escaping. The 4" drain lines then continue down the wall until approximately 6" off the floor where they open into air. The floor inside the drywell is poured concrete that extends up to elevation 549.92'. A 1" slot around the perimeter of the drywell floor provides for the installation of a joint sealer at the intersection of the concrete floor and drywell shell. The horizontal weld connecting the first and second course of drywell liner plates is approximately 8 inches above the floor. This area is accessible for examination from the inside surface and includes the top 0.37', approximately 4.4", of the SBR extending from elevation 549.92' to 550.29'.

In response to NRC Generic Letter 87-05, TVA reported in a 1988 follow-up letter the ultrasonic test (UT) measurements for all three BFN units and indicated no reading below nominal 1" plate thickness. It should be noted that while this response refers to a 1" nominal plate thickness, the plate in this area is nominally 1.125". The response also stated periodic leaking into the SBR had been observed on Unit 1; however, objective evidence of serious corrosion damage was not noted.

Since 1988, various corrective action reports have tracked leakage from the drains of all three units. Following the 1988 initial UT measurements taken in response to NRC Generic Letter 87-05, UT measurements were taken using consistent methodology in subsequent outages. Unit 1 data was obtained in 1999, 2004, 2008, 2010, 2020 and 2022 with satisfactory results. Unit 2 data was obtained in 2021 with satisfactory results. Unit 3 data was obtained in 2022 with satisfactory results. Those measurements that were consistent with Generic Letter 87-05 response were used for trending data. The data found was used in engineering evaluations of the inspection results. All results were acceptable.

Beyond the measurements taken with methodology consistent with the Generic Letter 87-05 response, additional measurements were taken, which provided general data regarding the liner condition at areas around the SBR. For Unit 1, additional measurements were taken in 2003, 2004, and 2006. For Unit 2, additional measurements were taken in 1997, 1999, 2003, 2009, and 2011. For Unit 3, additional measurements were taken in 1998, 2002, (visual inspection and manual depth measurements only, no UT was performed), and 2012. These additional inspections all resulted in minimum thickness measurements of greater than 1.0000".

In May 2022, a condition report was initiated as a result of a 2022 self-assessment on the BFN Aging Management Program. Multiple data collection methodologies were employed for ASME Section XI Subsection IWE regarding the SBR, some were consistent with Generic Letter 87-05 and others were not. This provided a substantial amount of data; however, only the collection method consistent with Generic Letter 87-05 was able to be trended. This issue was entered into the Corrective Action Program. This corrective action has resulted in collecting additional data during each BFN units subsequent refueling outage for trending.

- For Unit 1, SBR UT data was obtained in October 2022, the minimum wall thickness measured was 1.035" which is acceptable.
- For Unit 2, SBR UT data was obtained in March 2023, the minimum wall thickness measured was 1.028" which is acceptable.
- For Unit 3, SBR UT data is scheduled to be performed in February of 2024.

Based on the vast amount of SBR UT data that has been obtained to date, the corrosion rate is minimal and there is sufficient available margin for thinning at the SBR to support operation through the subsequent period of extended operation.

This example provides objective evidence that the ASME Section XI, Subsection IWE aging management program examinations are capable of detecting age-related degradation, deficiencies are entered into the Corrective Action Program, and actions are taken to evaluate and address deficiencies in accordance with ASME Code Section XI requirements, and follow-up inspections are performed.

Conclusion

The enhanced ASME Section XI, Subsection IWE program will provide reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.30 ASME Section XI, Subsection IWF

Program Description

The ASME Section XI, Subsection IWF program is an existing condition monitoring program that consists of periodic visual examination of supports for ASME Class 1, 2, 3, and MC piping and components for signs of degradation such as corrosion; cracking; deformation; misalignment of supports; missing, detached, or loosened support items; loss of integrity of welds; improper clearances of guides and stops; and improper hot or cold settings of spring supports and constant load supports. Bolting for Class 1, 2, and 3 piping and component supports will also be included and inspected for corrosion, loss of integrity of bolted connections due to self-loosening, and material conditions that can affect structural integrity.

The ASME Section XI, Subsection IWF program provides inspection and acceptance criteria and meets the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, 2007 Edition with addenda through 2008, and 10 CFR 50.55a(b)(2) for Class 1, 2, 3, and MC piping and components and their associated supports. The primary inspection method employed is visual examination. Indications are evaluated against the acceptance standards of ASME Code Section XI. Examinations that reveal indications are evaluated. Examinations that reveal flaws or relevant conditions that exceed the referenced acceptance standard will be expanded to include additional examinations during the current outage. The scope of inspection for supports is based on sampling of the total support population. The sample size varies depending on the ASME Code classification.

This program will emphasize proper selection of bolting material, lubricants, and installation torque or tension to prevent or minimize loss of bolting preload for structural bolting. The program will also include preventive actions for storage requirements of high-strength bolts and ensuring that molybdenum disulfide (MoS_2) and other lubricants containing sulfur are not used for structural bolting.

The requirements of ASME Code Section XI, Subsection IWF will be supplemented to include volumetric examination of a sampling high-strength bolting for cracking. every 10 years. This program will also include a one-time visual inspection within 5 years prior to the subsequent period of extended operation of an additional 5% of piping supports from the remaining IWF population that are considered most susceptible to age-related degradation. Inspections of elastomeric vibration isolation elements to detect hardening will also be included if the vibration isolation function is suspect.

The program will also perform inspections of the seismic restraints in the RHRSW pump pit.

NUREG-2191 Consistency

The enhanced ASME Section XI, Subsection IWF aging management program will be consistent with the 10 elements of aging management program XI.S3, ASME Section XI, Subsection IWF, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Implementing procedures will be revised to ensure the scope of this program includes support members, structural bolting, high-strength structural bolting [actual measured yield strength greater than or equal to 150 ksi (1,034 MPa)], anchor bolts, welds, support anchorage to the building structure, accessible sliding surfaces, constant and variable load spring hangers, guides, stops, and vibration isolation elements.

   Program Element Affected: Element 1 - Scope

2. Implementing procedures will be revised to ensure the acceptability of inaccessible areas (e.g., portions of supports encased in concrete, buried underground, or encapsulated by guard pipe) will be evaluated when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.

   Program Element Affected: Element 1 - Scope

3. Program will be enhanced to ensure the use of molybdenum disulfide (MoS_2) and other lubricants containing sulfur on structural bolting is prohibited.

   Program Element Affected: Element 2 - Preventative Actions

4. Program will be enhanced to ensure preventive measures include, when replacement of bolting is required, using only bolting material that has actual measured yield strength less than 150 ksi (1,034 MPa) and for bolting replacement and maintenance activities use of proper selection of bolting material and lubricants, and appropriate installation torque or tension, as recommended in EPRI documents (e.g., EPRI NP-5067 dated 1990 and EPRI TR-104213 dated December 1995), American Society for Testing and Materials (ASTM) standards, and American Institute of Steel Construction Specifications, as applicable.

   Program Element Affected: Element 2 - Preventative Actions

5. Implementing procedures will be revised to ensure that if bolting within the scope of the program consists of ASTM A325 and/or ASTM A490 bolts (including respective equivalent twist-off type ASTM F1852 and/or ASTM F2280 bolts), the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of Research Council for Structural Connections publication “Specification for Structural Joints Using High-Strength Bolts,” dated August 2014, will be used.

   Program Element Affected: Element 2 - Preventative Actions

6. Program will be enhanced to ensure that parameters monitored or inspected include corrosion; cracking, deformation; misalignment of supports; missing, detached, or loosened support items; general structural condition of weld joints and weld connection to building structure for loss of integrity; improper clearances of guides and stops; and improper hot or cold settings of spring supports, and constant load supports.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

7. Implementing procedures will be revised to ensure: accessible areas of sliding surfaces will be monitored for debris, dirt, or indications of excessive loss of material due to wear that could prevent or restrict sliding as intended in the design basis of the support; elastomeric or polymeric vibration isolation elements will be monitored for cracking, loss of material, and hardening; and bolting will be monitored for corrosion, loss of integrity of bolted connections due to self-loosening, and material conditions that can affect structural integrity.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

8. Implementing procedures will be revised to ensure that high strength bolting (actual measured yield strength greater than or equal to 150 ksi (1,034 MPa) in sizes greater than 1 inch nominal diameter (including ASTM A490 bolts and ASTM F2280 bolts), will be monitored for SCC.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

9. Implementing procedures will be revised to ensure that the provisions of ASME Code Section XI, 2007 Edition, 2008 Addenda, Subsection IWF are supplemented to include a one-time inspection of an additional 5 percent of the sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports. The one-time inspection will be conducted within 5 years prior to entering the subsequent period of extended operation. The additional supports will be selected from the remaining population of IWF piping supports. However, the responsible engineer should ensure that the sample includes components that are most susceptible to age-related degradation (i.e., based on time in service, aggressive environment, etc.).

   Program Element Affected: Element 4 - Detection of Aging Effects

10. Program will be enhanced to ensure that the extent, frequency, and examination methods are designed to detect, evaluate, or repair age-related degradation before there is a loss of component support intended function. The VT-3 examination method specified by the program will be used to reveal loss of material due to corrosion and wear, cracks, verification of clearances, settings, physical displacements, loose or missing parts, debris or dirt in accessible areas of the sliding surfaces, or loss of integrity at bolted connections.

    Program Element Affected: Element 4 - Detection of Aging Effects

11. Implementing procedures will be revised to ensure: the VT-3 examination method specified by the program will be used to also detect loss of material and cracking of elastomeric or polymeric vibration isolation elements; tactile inspection (feeling) of elastomeric or polymeric vibration isolation elements will be used to detect hardening if the vibration isolation function is suspect; and visual examinations that detect surface flaws which exceed acceptance criteria will be supplemented, in accordance with IWF-3200, by either surface or volumetric examinations to determine the character of the flaw.

    Program Element Affected: Element 4 - Detection of Aging Effects

12. Implementing procedures will be revised to ensure that for all high-strength bolting [actual measured yield strength greater than or equal to 150 ksi (1,034 MPa)] in sizes greater than 1 inch nominal diameter (including ASTM A490 and equivalent ASTM F2280), volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1 will be performed at least once per interval to detect cracking in addition to

the VT-3 examination. In each 10 year period during subsequent period of extended operation, a representative sample of bolts will be inspected. The sample of high-strength bolts greater than 1 inch nominal diameter subject to volumetric examination will consist of 20% of the population (for a material/environment combination) up to a maximum of 25 bolts per unit.

Program Element Affected: Element 4 - Detection of Aging Effects

13. Implementing procedures will be revised to ensure that if a component support does not exceed the acceptance standards of IWF-3400 but is repaired to as-new condition, the sample will be increased or modified to include another support that is representative of the remaining population of supports that were not repaired.

Program Element Affected: Element 5 - Monitoring and Trending

14. Implementing procedures will be revised to ensure the following conditions are identified as unacceptable in accordance with IWF-3410(a):
    - Loss of material, cracking, and hardening of elastomeric or polymeric vibration isolation elements that could reduce the vibration isolation function.

    The above conditions may be allowed to be accepted provided the technical basis for their acceptance is documented.

Program Element Affected: Element 6 - Acceptance Criteria

15. Program will be enhanced to ensure that identification of unacceptable conditions triggers an expansion of the inspection scope, in accordance with IWF-2430, and reexamination of the supports requiring corrective actions during the next inspection period, in accordance with IWF-2420(b). Additionally, in accordance with IWF-3122, ensure supports containing unacceptable conditions will be evaluated or tested or corrected before returning to service. Ensure corrective actions will be as delineated in IWF-3122.2. An alternative for evaluation or testing to substantiate structural integrity and/or functionality in accordance with IWF-3122.3 may also be used.

Program Element Affected: Element 7 - Corrective Actions

Operating Experience

The following examples of operating experience provide objective evidence that the ASME Section XI, Subsection IWF program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for the ASME Section XI Subsection IWF Program described in FSAR Section O.1.30. The purpose of the program effectiveness review was to verify that the existing aging management program activities, to identify and correct, as warranted, age-related degradation of components monitored by the Inspections of the ASME Section XI Subsection IWF Program, are being effectively implemented in the initial license renewal period of extended operation. The program effectiveness review was comprised of a review of inspection implementation activities to date and pertinent issues in the Corrective Action Program, searching for identified age-related degradation of components related to ASME Section XI Subsection IWF. The program manages the effects of aging on the BFN Units 1, 2, and 3 Steel Containment and integral attachments that are within the scope of license renewal. The review identified that inspections of components within the scope of the ISI Program are being performed in accordance with the extent and schedule described in ASME Section XI, Subsection IWF. The review identified that inspections performed within the program are effective at identifying age related degradation

of in-scope components before significant degradation has occurred. Age-related issues were evaluated in accordance with ASME Code Section XI requirements and corrective actions were taken to prevent further degradation in effective implementation of this aging management program.

2. A review of implementing activities and Corrective Action Program condition reports generated as a result of those activities shows was conducted examples reviewed include:
   - Inspections during Unit 1 refueling outage 10, in 2014, identified loose structural bolting on an RHR support. This issue was documented in the Corrective Action Program. An engineering evaluation determined that sufficient margin was available to document acceptability of the condition. The support remained qualified to all applicable design criteria requirements. A work order was generated to correct the condition. Corrective action was initiated to verify the loose bolting was corrected and to perform post maintenance inspections.
   - Inspections during Unit 2 refueling outage 21 in 2021 identified that a variable spring support on the main steam line C in the Unit 2 Turbine Building steam tunnel was out of its load setting range of 6482 lbs to 6670 lbs. This issue was documented in the Corrective Action Program. Actions included resetting the spring load to within the design load range and performance of an engineering evaluation which determined that with the out of specification setting the variable spring support continued to perform its intended design function without any adverse effect on the pipe support components or the affected piping system.
   - Inspections during Unit 3 refueling outage 20 in 2022 identified loose nuts on concrete anchor bolts for a mechanical snubber support were identified. The nuts were not backed off the bolt but were able to be loosened by hand. No physical damage to studs was observed. This issue was documented in the Corrective Action Program. The loose bolting was corrected and re-examined. No recordable indications were observed. No successive or additional exams were determined to be necessary.

   This internal operating experience provides objective evidence that pipe supports are inspected, and the inspections are effective at identifying degradation. Degraded conditions are entered into the Corrective Action Program, evaluated to determine the cause, impact on required functions, and corrective actions taken to ensure long term integrity, which include follow-up inspections to verify the effectiveness of corrective actions.

3. There have been two QA-Site Audit Reports conducted during the period of extended operation of Engineering Programs that included the ASME Section XI, Subsection IWF, ISI program. Both QA-Site Audit Reports found the ASME Section XI, Subsection IWF, ISI program to be satisfactory with no deficiencies or recommendations. There have been two self-assessments associated with the BFN License Renewal programs during the period of extended operation, the BFN 2020 License Renewal Self-Assessment and the BFN 2022 Aging Management Program Self-Assessment. No deficiencies associated with the ASME Section XI Subsection IWF program were identified.

   This example demonstrates that periodic self-assessments of the ASME Section XI, Subsection IWF aging management program have been performed to identify and correct program elements that need improvement to maintain the quality performance of the program.

4. A loose nut and displacement of baseplate and anchor bolting was found at a High Pressure Coolant Injection (HPCI) System support. The shank of one anchor was visible between the wall and baseplate. The issue was entered into the Corrective Action Program in October 2014. Civil Design Engineering performed a walkdown of the HPCI pipe support. It was

observed that the support base plate does not sit flat on the concrete wall as there are gaps along the underside edges of the plate around the perimeter of the plate. The largest gap between the underside of the base plate and the concrete wall surface was at the south vertical side (left side) and around the corners of the base plate which measured slightly under 3/16". The remaining gaps around the remainder of the plate were 1/8" or less. The gaps between the baseplates and the concrete were determined to be acceptable. The nut on the lower south bolt was loose on the anchor bolt, but the anchor bolt appeared to be solidly set in the concrete wall when checked by hand. There did not appear to be any wear marks or distortions on the support between the base plate and the attachment to the HPCI pipe, which would be an indication if severe loading had occurred. The condition of the concrete around the anchors most likely occurred during installation. A review of the engineering calculation determined that there is sufficient design margin in the base plate anchors so that even if the loose bolt would not be effective in carrying any of its designed load, the remaining three anchors have sufficient capacity to sustain the addition load from the anchor with the loose bolt. The support remains fully qualified for the condition described herein. A Work Order was performed that re-aligned the baseplate and torqued the loose nut to 170 ft/lbs in accordance with applicable specifications.

This example provides objective evidence that as inspection conditions are observed that do not meet requirements, the condition is entered into the Corrective Action Program, and evaluated and corrected. This will support effectively managing aging by correcting degradation prior to failure or loss of intended function during the subsequent period of extended operation.

Conclusion

The enhanced ASME Section XI, Subsection IWF program will provide reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.31 10 CFR Part 50, Appendix J

Program Description

The 10 CFR 50, Appendix J aging management program is an existing performance monitoring program that ensures all containment pressure-retaining components are managed for age-related degradation. The scope of the program includes the primary containment system, which consists of a primary containment structure (containment), and a number of electrical, mechanical, equipment hatch, and personnel air lock penetrations. The program monitors leakage rates through the primary containment pressure boundary to detect degradation of the primary containment pressure boundary.

The program consists of tests performed in accordance with the regulations and guidance provided in 10 CFR 50, Appendix J, “Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors,” Option B, NEI 94-01, Revision 2-A and Revision 3-A, “Industry Guideline for Implementing Performance-Based Options of 10 CFR Part 50, Appendix J,” and subject to the requirements of 10 CFR Part 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants.”

Containment leak rate tests are performed using plant procedures to assure that leakage through the containment and systems and components penetrating primary containment does not exceed allowable leakage limits specified in the Technical Specifications. An integrated leak rate test (ILRT) is performed during a period of reactor shutdown at the frequency specified in 10 CFR Part 50, Appendix J, Option B and station Primary Containment Leakage Rate Testing Program. Local Leak Rate Tests (LLRT) are performed on primary containment isolation valves and containment access penetrations at frequencies that comply with the requirements of 10 CFR 50, Appendix J, Option B and station Primary Containment Leakage Rate Testing Program. Components required to be leak rate tested or excluded from testing are identified in FSAR Table 5.2-2. General visual inspection of the accessible interior and exterior surfaces of the containment structures and components are performed in conjunction with the ASME Section XI, Subsection IWE program (B.2.1.29).

Monitoring and trending is performed by comparing valve and penetration leakage from test results to administrative leakage limits that are set lower than the regulatory acceptance criteria. Test or inspection results that do not satisfy established criteria are entered into the Corrective Action Program for evaluation or repair.

NUREG-2191 Consistency

The 10 CFR 50, Appendix J aging management program is consistent with the 10 elements of aging management program XI.S4, 10 CFR 50, Appendix J, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the 10 CFR 50, Appendix J program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for the 10 CFR 50 Appendix J Program described in FSAR Section O.1.31 in support of preparing the BFN Subsequent License Renewal Application. The purpose of the program effectiveness review was to verify that the existing aging management program activities, to identify and correct, as warranted, age-related degradation of components monitored by the 10 CFR 50 Appendix J Program, are being effectively implemented in the initial license renewal period of extended operation. The program manages the loss of material for systems penetrating the primary containment and change in properties including cracking of gaskets and seals for the primary containment pressure boundary access penetrations.The program effectiveness review was comprised of a review of inspection implementation activities and a review of operating experience within the Corrective Action Program for identified age-related degradation of in-scope components. The inspections performed in accordance with the Primary Containment Leakage Rate Testing Program have identified age-related deficiencies associated with internal valve seat leakage of primary containment isolation valves and degradation of gaskets and seals associated with primary containment pressure boundary access points. These deficiencies have been identified during performance of leak rate testing of components in accordance with 10 CFR 50, Appendix J. The results of these inspections were evaluated under the Corrective Action Program, which provided the mechanism for repair to achieve acceptable

leakage results. These inspections, along with the evaluation of deficiencies within the Corrective Action Program, have resulted in the effective implementation of this aging management program. This aging management program effectiveness review determined that the program is being implemented in accordance with the Primary Containment Leakage Rate Testing Program as described in FSAR Section O.1.31.

This operating experience provides objective evidence that the current Primary Containment Leakage Rate Testing Program is effectively managing aging effects of components that make up the primary containment boundary. Continued implementation of the 10 CFR 50, Appendix J aging management program will assure that components within the scope of the program will continue to perform their intended functions during the subsequent period of extended operation.

2. The engineer responsible for this program keeps records of the results of the “As Found” and “As Left” leak rate values for the most recent three outages (at the time of this report) for trending purposes. Based on the review of the LLRT results from the Unit 1 Fall 2022 refueling outage, it is shown that the Appendix J program performance has addressed the elements of the Aging Management Program. There was no indication of any missed or incomplete inspections. All LLRTs not meeting acceptance criteria were corrected except for the HPCI Steam Outboard Isolation Valve. The leak rate was at 44.4 standard cubic feet per hour (scfh) versus an administrative limit of 30 scfh. It was decided to accept the leakage as is, and schedule repair for the next outage opportunity. The Unit 1 Primary Containment Total Leak Rate was a Total As-Left maximum path leak rate of 197.3 scfh versus an acceptance criteria of 640.3 scfh.

   Based on the review of the LLRT results from the Unit 2 Spring 2023 refueling outage, it is shown that the Appendix J program performance has addressed the elements of the Aging Management Program. There was no indication of any missed or incomplete inspections. All LLRTs not meeting acceptance criteria were corrected except for the Drywell Equipment Drain Sump Outboard Isolation Valve. The leak rate was at 8.3 scfh versus the administrative limit of 6 scfh. It was decided to accept the leakage as is and schedule repair for the next outage opportunity. The Unit 2 Primary Containment Total Leak Rate was a Total As-Left maximum path leak rate of 175.8 scfh versus an acceptance criteria of 640.3 scfh.

   Based on the review of the LLRT results from the Unit 3 Spring 2022 refueling outage, it also is shown that the Appendix J program performance has addressed the elements of the Aging Management Program. There was no indication of any missed or incomplete inspections. All failed LLRT's were corrected. The Unit 3 Primary Containment Total Leak Rate was a Total As-Left maximum path leak rate of 194.5 scfh versus an acceptance criteria of 640.3 scfh.

   This example provides objective evidence that the 10 CFR Part 50, Appendix J program effectively manages leakage from the primary containment and systems and components that penetrate primary containment, to ensure that the measured leakage rates do not exceed allowable leakage rate values as specified in the Technical Specifications and associated bases.

3. During the October 2020 performance of a leak rate test for the Unit 1 A Outboard Main Steam Isolation Valve, a leak rate of 108.1 scfh was obtained. The value exceeded the Technical Specification limit of 100 scfh. The valve seats were reworked. The As-Left leak rate value was well within limits at 9.5 scfh.

   This example provides objective evidence that conditions of components exceeding the allowable leakage rate acceptance criteria are being entered into the Corrective Action Program, evaluated, repaired, and subsequently retested in accordance with the 10 CFR Part 50, Appendix J program.

4. NRC Information Notice (IN) 92-20, “Inadequate Local Leak Rate Testing,” was issued to alert licensees of problems with local leak rate testing of two-ply stainless steel bellows. The information notice discusses an event at Quad Cities Nuclear Power Station Unit 1 where a Type B test on the containment penetration bellows could identify leakage, but could not accurately quantify the extent of the leakage. The event at Quad Cities revealed that the local leak rate testing performed between the two plies could not be relied upon to accurately measure the leakage rate that would occur through the bellows under accident conditions. The two plies of the bellows were in contact with each other, restricting the flow of the test medium to the crack locations. Any two-ply bellows of similar construction may be susceptible to this problem. The two-ply expansion bellows installed at BFN incorporate a stainless steel mesh between the plies to eliminate binding as described in the bellows event at Quad Cities and allows full pressure to be transmitted to all portions of the bellows during Appendix J testing. Therefore, this is not an issue at BFN.

   In August 2012, BFN also reviewed event report, Institute of Nuclear Power Operations (INPO) IER3-12-65, Fire In Containment During Containment Integrated Leak Rate Test. This event report discussed a fire in the Containment during a Containment Pressure test at the Ringhals Generating Station Unit 2. The fire was started by a plugged in vacuum cleaner that had an electrical fault, and spread by combustibles that were left in the containment. This test is normally conducted with the Unit in Mode 5, at the end of an outage just before restart, after fuel had been reloaded, the reactor reassembled, and containment cleared and cleaned to the same level as during power operations. Station Managers decided to pull up the containment air test to Mode 7 to save time in the overall outage schedule because of unrelated equipment maintenance challenges. In response to this incident, BFN personnel verified that Final Pre-pressurization Check section of each of the BFN units Primary Containment Integrated Leak Rate Test procedures, included steps that ensure the conditions described in INPO IER3-12-65 do not exist prior to pressurizing the containment. This incident has been used in the Containment Integrated Leak Rate Test Infrequently Performed Test of Evolution pre-test briefing.

   These examples provide objective evidence that industry operating experience is being reviewed and evaluated to confirm that station testing procedures are effective to maintain containment integrity.

Conclusion

The existing 10 CFR 50, Appendix J program provides reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.32 Masonry Walls

Program Description

The BFN Masonry Walls aging management program is an existing condition monitoring program implemented as part of the Structures Monitoring Program and includes all masonry walls identified as performing intended functions in accordance with 10 CFR 54.4. Masonry walls consist of solid or hollow concrete block, mortar, grout, steel bracing, reinforcing and supports. The Masonry Walls program is based on guidance provided in NRC Inspection and Enforcement (IE) Bulletin 80-11, “Masonry Wall Design,” and NRC Information Notice 87-67, "Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11."

The Masonry Walls program manages inspections of masonry walls for loss of material and cracking, and increases in gaps between the masonry wall supports and the masonry walls that could impact the intended function or potentially invalidate its evaluation basis. The program relies on periodic visual inspections, conducted at a frequency not to exceed five years, to monitor and maintain the condition of masonry walls within the scope of subsequent license renewal so that the established evaluation basis for each masonry wall remains valid during the subsequent period of extended operation.

The objective of the Masonry Walls program is to manage aging effects of loss of material and cracking of masonry units and mortar, and increases in gaps between the masonry wall supports and the masonry walls that could impact the intended function or potentially invalidate its evaluation basis. Conditions found to be "acceptable with deficiencies" or deemed to be "unacceptable" are documented and entered into the Corrective Action Program for evaluation, which results in analysis, repair, or replacement, as necessary. Nonsafety-related masonry walls, with a structural intended function in structures that are in-scope for subsequent license renewal, are also inspected as part of the Masonry Walls program. Masonry walls that are considered fire barriers are also managed by the Fire Protection program (B.2.1.15). Steel bracing, reinforcing and supports that are part of the masonry wall design are managed by the Structures Monitoring program (B.2.1.33).

<u>NUREG-2191 Consistency</u>

The enhanced Masonry Walls aging management program will be consistent with the 10 elements of aging management program XI.S5, Masonry Walls, specified in NUREG-2191.

<u>Exceptions to NUREG-2191</u>

None.

<u>Enhancements</u>

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Revise implementing procedures to address specific primary parameter monitored of cracking or loss of material at the mortar joints and gaps between the supports and masonry walls.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

2. Revise implementing procedures to require inspection results to be documented and compared to previous inspections to identify changes or trends in the condition of masonry walls.

   Program Element Affected: Element 5 - Monitoring and Trending

3. Revise implementing procedures to require identified degradation, where practical, to be projected until the next scheduled inspection.

   Program Element Affected: Element 5 - Monitoring and Trending

4. Revise implementing procedures to require results to be evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended

functions throughout the subsequent period of extended operation based on the projected rate of degradation.

Program Element Affected: Element 5 - Monitoring and Trending

5. Revise implementing procedures to ensure crack widths and lengths, and gaps between supports and masonry walls, that approach or exceed acceptance criteria are measured and assessed for trends.

Program Element Affected: Element 5 - Monitoring and Trending

6. Revise implementing procedures to encourage the use of photographs or surveys and to indicate photographic records may be used to document and trend the type, severity, extent and progression of degradation.

Program Element Affected: Element 5 - Monitoring and Trending

7. Revise implementing procedures to require each masonry wall that has observed degradation (e.g., shrinkage and/or separation, cracking of masonry walls, cracking or loss of material at the mortar joints and gaps between the supports and masonry walls) to be assessed against the evaluation basis to confirm that the degradation has not invalidated the original evaluation assumptions or impacted the capability to perform the intended functions.

Program Element Affected: Element 6 - Acceptance Criteria

8. Revise implementing procedures to require further evaluation to be conducted to determine if corrective action is required when the degradation is determined to impact the intended function of the wall or invalidate its evaluation basis.

Program Element Affected: Element 6 - Acceptance Criteria

9. Revise implementing procedures to require degraded conditions that exceed acceptance criteria and are accepted without repair or other corrective actions are technically justified or supported by an engineering evaluation.

Program Element Affected: Element 6 - Acceptance Criteria

10. Revise implementing procedures to adjust inspection frequencies ,as determined by the Corrective Action Program, If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection.

Program Element Affected: Element 7 - Corrective Actions

Operating Experience

The following examples of operating experience provide objective evidence that the Masonry Wall program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for the Masonry Wall Program described in FSAR Section O.1.32 in support of preparing the BFN Subsequent License Renewal Application. The purpose of the program effectiveness review was to verify that the ability of the Masonry Wall program to manage aging effects so that the evaluation basis established for each masonry wall within the scope of license renewal remains valid through the period of extended operation. This program was an enhancement to the previously existing Structures Monitoring program to specify the structures with masonry walls within the scope of license renewal are clearly identified and the qualification requirements for personnel who perform masonry wall walkdowns within the scope of license renewal are clarified. The Masonry Wall program uses periodic inspections to detect aging effects. These inspections are conducted along with the inspections conducted for the Structures Monitoring program. These inspections are performed as directed by procedures for Maintenance Rule

Performance Indicator Monitoring, Trending, and Reporting, and using the guidelines and inspection reports in the procedure for Walkdown of Structures for Maintenance Rule and License Renewal and Aging Management Program Basis Document Masonry Wall Program. These inspections take place throughout the 5 year inspection period. Individual results are maintained for each inspection. Specific inspection criteria for masonry walls are contained in plant procedures. Individual deficiencies are documented in the Corrective Action Program. After each 5 year period, the overall results of the structures inspection are evaluated and documented in a single report. This reports contains data for the Masonry Wall program and the Structure Monitoring program. The 5 year report is documented as a Structural Maintenance Rule and License Renewal Inspection calculation. A review of the 5 year Structures Monitoring calculations covering the period from 2012 through 2022 (three calculations) was conducted. There were no examples of masonry wall degradation where structural integrity was effected or challenged an intended function for License Renewal. There were minor issues that were evaluated as acceptable. These evaluations are documented in the calculation.

This operating experience provides objective evidence that the inspections performed by this program effectively monitor the condition of masonry walls to assure that masonry walls will be able to continue to perform their intended functions and that appropriate aging management program activities will continue to be performed during the subsequent period of extended operation.

2. In February 2013, a crack was identified on the exterior masonry wall of the Unit 3 Reactor Water Cleanup heat exchanger room. The issue was entered into the Corrective Action Program, and an evaluation was performed which determined that the defect was cosmetic in nature and is not a functional concern. Two additional masonry wall indications were evaluated and determined that the walls involved were not in-scope for License Renewal, as documented in the 2017 calculation and the Corrective Action Program. Although not in-scope for License Renewal, these two indications were evaluated and concluded that the identified defect did not compromise the structural integrity of the wall.

   This operating experience provides objective evidence that the inspection practices, and the Corrective Action Program, effectively monitor and evaluate the condition of masonry walls to assure that masonry walls will be able to continue to perform their intended functions and that appropriate aging management program activities will continue to be performed during the subsequent period of extended operation.

3. The Masonry Walls aging management program is implemented as an element of the Structures Monitoring program, which is monitored under the Maintenance Rule. The Maintenance Rule implementation procedure includes steps to monitor plant-specific performance data and to evaluate industry operating experience. A review of Maintenance Rule program periodic reports spanning 2012 through 2021 concluded that the Structures Monitoring program was acceptable based upon all structures in the scope of the program, which includes masonry walls, being in acceptable condition and subject to normal monitoring in accordance with the requirements of 10 CFR 50.65(a)(2).

   This operating experience provides objective evidence that the overall Structures Monitoring program, which includes the Masonry Walls program, is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience.

Conclusion

The enhanced Masonry Walls aging management program will provide reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.33 Structures Monitoring

Program Description

The BFN Structures Monitoring aging management program is an existing condition monitoring program based on the requirements of 10 CFR 50.65 and the guidance provided in Regulatory Guide 1.160, Rev 2, and Nuclear Management and Resources Council (NUMARC) 93-01, Rev 2.

The BFN Structures Monitoring program consists primarily of periodic visual inspections of structures and structural commodities for evidence of deterioration or degradation, such as described in the American Concrete Institute (ACI) Standards 349.3R-02, ACI 201.1R-08, and Structural Engineering Institute/American Society of Civil Engineers Standard (SEI/ASCE) 11-99. Quantitative acceptance criteria for concrete inspections are based on ACI 349.3R-02.

Inspections and evaluations are performed by personnel qualified to monitor structures and components for applicable aging effects from degradation mechanisms, such as those described in the American Concrete Institute (ACI) Standards 349.3R-02, ACI 201.1R-08 and Structural Engineering Institute/American Society of Civil Engineers Standard (SEI/ASCE) 11-99. Identified aging effects are evaluated by qualified personnel using criteria derived from industry codes and standards contained in the plant current licensing basis, including ACI 349.3R-02, and SEI/ASCE 11-99, and the American Institute of Steel Construction (AISC) specification, as applicable. All in-scope structures shall be monitored by visual inspection on an interval not to exceed five years. The program shall include provisions for more frequent inspections based on an evaluation of the observed degradation. The five-year frequency is consistent with ACI 349.3R-02.

The Corrective Action Program requires the initiation of a Condition Report (CR) for actual or potential problems, including plant equipment degradation, damage, failure, malfunction, or loss of function. Site documents that implement aging management programs for subsequent license renewal direct that a CR be initiated whenever non-conforming conditions are found (i.e., the acceptance criteria are not met). The Corrective Action Program specifies that a CR be initiated for condition identification, assignment of significance level and investigation class, investigation, corrective action determination, investigation report review and approval, action tracking, and trend analysis.

The BFN Structures Monitoring program also includes preventive actions and measures 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.

Protective coatings minimize corrosion by limiting exposure to the environment. However, protective coatings are not credited in the determination of aging effects requiring management for structures or structural commodities with the scope of this program. Protective coatings for structures or structural commodities with the scope of this program are not credited for subsequent license renewal but are used to indicate aging effects of the base material.

The BFN Structures Monitoring program also includes periodic sampling and testing of groundwater, and the need to assess the impact of any changes in groundwater chemistry on below grade concrete structures.

NUREG-2191 Consistency

The enhanced Structures Monitoring aging management program will be consistent with the 10 elements of aging management program XI.S6, Structures Monitoring, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements

1. Revise implementing procedures to add the following structures to the scope:
   - Discharge Control Structure
   - Circulating Water Conduit
   - Low Level Radwaste (LLRW) Storage Facility
   - Supplemental Diesel Generator Building
   - Nitrogen Storage Tank Foundation
   - Radwaste/Condensate Water Storage Tanks Tunnels
   - Yard Structures, General
   - Structural Commodities: Hazard Barriers and Elastomers; Miscellaneous Steel; and Penetrations and Sleeves

   Program Element Affected: Element 1 - Scope of Program

2. 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, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” dated August 2014, will be used.

   Program Element Affected: Element 2 - Preventive Actions

3. Revise implementing procedures to be consistent with ACI 349.3R-02 and SEI/ASCE 11-99 for selection of parameters to be monitored or inspected for concrete and steel structural elements and for steel liners, joints, coatings, and waterproofing membranes.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

4. Ensure inspections include the following indicators to identify cracking due to expansion from reaction with aggregates:
    - Surface aggregate popouts
    - Pattern cracking with darkened crack edges
    - Water ingress
    - Misalignment Inspections

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

5. Revise implementing procedures to ensure steel, aluminum, and non-ferrous material components are monitored for cracking, loss of material due to corrosion or mechanical wear, and general degradation.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

6. Revise implementing procedures to ensure accessible sliding surfaces will be monitored for indication of significant loss of material due to wear or corrosion, and for accumulation of debris or dirt.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

7. Revise implementing procedures to ensure elastomeric vibration isolators, membranes, structural sealants, and seismic joint fillers are monitored for cracking, loss of material, hardening, separation and leakage.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

8. Revise implementing procedures to include monitoring for earth berms for loss of material and loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, and seepage.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

9. Revise implementing procedures to include monitoring of ground water chemistry for pH, chlorides, and sulfates on a frequency not to exceed five years that accounts for seasonal variances from locations that are representative of the groundwater in contact with the structures within the scope of this aging management program. Adverse results will be entered into the Corrective Action Program.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

10. Revise implementing procedures to monitor and trend for signs of concrete or steel reinforcement degradation if through-wall leakage or groundwater infiltration is identified.

    Program Element Affected: Element 3 - Parameters Monitored or Inspected

11. Revise implementing procedures that inspection of concrete structures, qualifications of inspection and evaluation personnel will be in accordance with ACI 349.3R-02.

    Program Element Affected: Element 4 - Detection of Aging Effects

12. Revise implementing procedures to require indications of groundwater infiltration or through-concrete leakage to be assessed for aging effects. This may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels. When leakage volumes allow, assessments may include analysis of the leakage pH, along with mineral, chloride, sulfate, and iron content in the water. The responsible engineer for this program will also evaluate groundwater chemistry results that are sampled from locations representative of the water in contact with structures within the scope of subsequent license renewal.

    Program Element Affected: Element 4 - Detection of Aging Effects

13. Revise implementing procedures to state visual inspections may need to be enhanced or supplemented with nondestructive examination, destructive testing and/or analytical methods, based on the conditions observed or the parameter being monitored.

    Program Element Affected: Element 4 - Detection of Aging Effects

14. Revise implementing procedures to require visual inspection of elastomeric elements to be supplemented by tactile inspection to detect hardening if the intended function is suspect.

    Program Element Affected: Element 4 - Detection of Aging Effects

15. Revise implementing procedures to require the acceptability of inaccessible areas to be evaluated when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. The acceptability of inaccessible areas will also be assessed by examining representative samples of exposed portions of below grade concrete, when excavated for any reason.

    Program Element Affected: Element 4 - Detection of Aging Effects

16. Revise implementing procedures to establish quantitative baseline inspection data for structures and structural commodities for which baseline inspection data has not been established or for which the baseline acceptance criteria used are not comparable to the GALL-SLR acceptance criteria, prior to the subsequent period of extended operation.

    Program Element Affected: Element 5 - Monitoring and Trending

17. Revise implementing procedures to require quantitative measurements and qualitative information to be recorded and trended for findings that exceed the acceptance criteria for all applicable parameters monitored or inspected.

    Program Element Affected: Element 5 - Monitoring and Trending

18. Ensure acceptance criteria for each structure and aging effect that are derived from BFN design basis documents, applicable codes and standards that include but are not limited to ACI 349.3R-02, SEI/ASCE 11-99, or relevant AISC specifications and consider industry and plant operating experience.

    Program Element Affected: Element 6 - Acceptance Criteria

19. Revise implementing procedures to ensure no evidence of popouts, map and pattern cracking with darkened crack edges, water ingress, and/or misalignment inspections; any evidence of these will require an engineering evaluation.

    Program Element Affected: Element 6 - Acceptance Criteria

20. Revise implementing procedures to ensure no significant cracking, no significant loss of material due to corrosion or mechanical wear, and no significant signs of general degradation for steel, aluminum, and non-ferrous material components.

    Program Element Affected: Element 6 - Acceptance Criteria

21. Revise implementing procedures to note loose bolts and nuts are not acceptable unless accepted by engineering evaluation for structural components within this aging management program.

    Program Element Affected: Element 6 - Acceptance Criteria

22. Revise implementing procedures to add following acceptance criteria for structural steel bracing and edge supports associated with masonry block walls:

    - No adverse or significant deflection or distortion
    - No loose bolts (unless accepted by engineering evaluation)

    Program Element Affected: Element 6 - Acceptance Criteria

23. Revise implementing procedures to require no signs of distress that could indicate degradation of the underlying material for painted or coated areas.

    Program Element Affected: Element 6 - Acceptance Criteria

24. Revise implementing procedures to ensure there are no indications of excessive loss of material due to corrosion or wear and no debris or dirt that could restrict or prevent sliding of the surfaces as required by design.

    Program Element Affected: Element 6 - Acceptance Criteria

25. Revise implementing procedures to ensure inspections for elastomeric vibration isolators, membranes, structural sealants, and seismic joint fillers the following acceptance criteria are met:
    - Elastomeric membranes, structural sealants, and seismic joint fillers are acceptable if the observed loss of material, cracking, hardening, separation, and/or leakage will not result in the loss of sealing.
    - Elastomeric vibration isolation elements are acceptable if there is no loss of material, cracking, hardening, separation, and/or leakage that could lead to the reduction or loss of isolation function.

    Program Element Affected: Element 6 - Acceptance Criteria

26. Revise implementing procedures to add following acceptance criteria for earth berms:
    - No significant loss of material
    - No significant loss of form
    - No evidence of erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, or seepage that could lead to a loss of material or form.

    Program Element Affected: Element 6 - Acceptance Criteria

27. Revise implementing procedures to ensure the groundwater chemistry has been determined to be within the following parameters: pH > 5.5, chlorides < 500 ppm, and sulfates <1,500 ppm. Groundwater chemistry values indicative of aggressive groundwater/soil (pH < 5.5, chlorides > 500 ppm, or sulfates > 1,500 ppm) will be assessed for impact on concrete structural elements. This may include evaluations, destructive testing, and/or focused inspections of representative accessible (leading indicator) or below-grade, inaccessible concrete structural elements exposed to aggressive groundwater/soil, on an interval not to exceed 5 years.

    Program Element Affected: Element 6 - Acceptance Criteria

<u>Operating Experience</u>

The following examples of operating experience provide objective evidence that the Structures Monitoring Program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for Structures Monitoring Program described in FSAR Section O.1.33 in support of preparing the BFN Subsequent License Renewal Application. The purpose of the program effectiveness review was to verify that the intent of the existing aging management program activities to identify and correct, as warranted, age-related degradation of structures and structural components within the scope of the License Renewal, is being effectively implemented in the initial license renewal period of extended operation. The original activities included visual inspection of structures and structural components, documentation of findings, and follow-up actions in the Corrective Action Program. The Structures Monitoring Program existed prior to License Renewal and

continued into the period of extended operation. The program effectiveness review was comprised of a review of visual inspection implementation activities, including results to date, and pertinent issues in the Corrective Action Program. These inspections have been completed on a 5-year basis. Included in this review are pre-period of extended operation visual inspection results. The reviews did not identify significant age-related degradation of structures and structural components that impacted the ability to perform intended functions. Only minor degradation that would not impact performance of intended functions was observed. The degradation that was identified in the inspections were entered into the Corrective Action Program. There were no issues in either the pre-period of extended operation implementation or the current period of extended operation related operating experience items where a structures and structural components was unable to perform its intended function due to age-related degradation.

This operating experience provides objective evidence that inspection activities taken as part of the Structures Monitoring Program will assure that degradation of in-scope components in the Structures Monitoring program will be identified while they are able to continue to perform their intended functions, and that appropriate aging management will be performed during the subsequent period of extended operation.

2. In 2022, a program effectiveness review performed for the Structures Monitoring Program evaluated the status of the Work Orders (WOs) developed from the Condition Reports (CRs) identified in the Maintenance Rule and License Renewal Inspection Reports. This evaluation showed an inconsistency in the completion of the Work Orders (WOs) developed from the CRs. For example, of the 36 WOs written for deficiencies in the 2007-2012 report (the report prior to period of extended operation) show that 15 were completed, 7 are in planning (at least 10 years old), and 10 were canceled. The 2012-2017 report had similar results. A total of approximately 70 work orders created for degradation identified from the 2007 to 2017 aging management structural inspections have not been worked, either are still in planning or canceled. Although the conditions were evaluated at the time of identification of the degradation, no evaluation of the effect on aging management as a result of canceling or delaying these work orders was performed. This condition was entered into the Corrective Action Program with the actions taken which include an evaluation of each delayed or canceled WO for the effect on the component or structure. Additional actions required documentation of acceptable monitoring and inspection intervals for each defect, and documentation of recommended time element for repair, and noting elevation of concern related to repair time if the repair is delayed.

   This operating experience provides objective evidence that effectiveness reviews, and the Corrective Action Program, are used to detect gaps in program performance, and to address those gaps. Additionally, this provides assurance that degradation of structures and components in the Structures Monitoring Program are evaluated during work delays and are monitored to ensure that additional degradation which threaten intended functions is detected. This provides assurance that the structures and components covered by the Structures Monitoring Program will continue to perform their intended functions, and that appropriate aging management will be performed during the subsequent period of extended operation.

3. On January 21, 2022, a Condition Report was entered into the Corrective Action Program which identified a generic issue regarding aggressive soil environments effects on concrete structures, requiring site specific further evaluation. The evaluation addressed concrete structures within the scope for License Renewal, their proximity to ground water, and actual ground water pH values from sample wells. EPRI Technical Report, Long-Term Operations: Subsequent License Renewal Aging Effects for Structures and Structural Components

(Structural Tools), was used during the evaluation. The evaluation determined, based on the locations of the structures and the pH readings from the sample wells, that there is not a concern for degradation of the concrete structures. This evaluation was documented in the Corrective Action Program.

This operating experience provides objective evidence that the Corrective Action Program, along with industry guidance, is used during evaluations of structures and components within the scope of License Renewal. This provides assurance that the structures and components covered by the Structures Monitoring Program will continue to perform their intended functions, and that appropriate aging management will be performed during the subsequent period of extended operation.

4. The 2017 Maintenance Rule and License Renewal Inspection Report identified concrete degradation in Unit 2 Torus Room, Bay 1, and additional degradation in Bay 16. The condition was entered into the Corrective Action Program and the initial evaluation documented the degradation did not compromise structural integrity of the concrete. The cause of the degradation was water intrusion from an external source. The evaluation did not determine the source of the water intrusion causing the degradation. A WO was initiated to repair the degradation. The WO is in planning, and the degradation has not been repaired. The 2019 and 2022 Maintenance Rule and License Renewal Inspections Report again identified the Bay 1 degradation. An additional issue of corrosion on a torus support was identified and entered in the Corrective Action Program. Actions taken from the Corrective Action Program for this condition included cleaning of the corrosion and assessment of the support condition. The evaluation determined that there was no measurable loss of material and was acceptable.

   This operating experience provides objective evidence that the Corrective Action Program is used to plan and perform activities to investigate conditions which is causing degradation of structures and components in the Structures Monitoring Program. This provides assurance that the structures and components covered by the Structures Monitoring Program will continue to perform their intended functions, and that appropriate aging management will be performed during the subsequent period of extended operation.

5. During a refueling outage in February 2023, when the Condenser Circulating Water (CCW) System was shutdown, the water intrusion into the plant was observed to stop. A subsequent inspection of the CCW inlet conduit identified four leaking seams in the conduit. This inspection was documented in the Corrective Action Program to repair the leaking seams. These leaks were repaired during the unit outage in which they were discovered.

   This operating experience provides objective evidence that the Corrective Action Program is used to plan and perform activities to investigate conditions which is causing degradation of structures and components in the Structures Monitoring Program. This provides assurance that the structures and components covered by the Structures Monitoring Program will continue to perform their intended functions, and that appropriate aging management will be performed during the subsequent period of extended operation.

6. A TVA Corporate License Renewal self-assessment, which included Structures Monitoring, was performed in June 2020, and was documented in the Corrective Action Program. It was identified that the BFN Structure Monitoring Aging Management Program Basis Document procedure requires an inspection of each structure every five years, however the implementing procedure only required a five-year structures report. This issue was entered into the Corrective Action Program and actions were developed and completed to revise the implementing procedure to clarify that each structure is inspected every five years. Additionally, it was identified during the June 2020 TVA Corporate License Renewal

self-assessment that aging management trend codes were not being used for Condition Reports where degradation was identified during structures inspections. This use of the trend code is required by the structure's inspection procedure. This was documented in the Corrective Action Program. Corrective action was developed and completed where the expectation and requirement to use the trend code was shared by Engineering leadership with the civil engineering group.

An additional TVA Corporate License Renewal self-assessment, which included Structures Monitoring, was performed in 2022, and was documented in the Corrective Action Program. One strength and four learning opportunities were identified.

This operating experience provides objective evidence that evaluations and assessments are used in the Structures Monitoring Program to identify deficient conditions in the program, and for the Corrective Action program to correct those conditions. This provides assurance that the structures and components covered by the Structures Monitoring Program will continue to perform their intended functions during the subsequent period of extended operation.

Conclusion

The enhanced Structures Monitoring Program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.34 Inspection of Water-Control Structures Associated with Nuclear Power Plants

Program Description

The BFN Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program is an existing condition monitoring program that consists of inspection and surveillances of raw water-control structures associated with emergency cooling systems and/or flood protection to identify aging effects prior to loss of intended functions. The program also includes requirements for structural steel and structural bolting associated with water-control structures as well as monitoring raw service water to ensure it does not become aggressive to concrete.

The program incorporates parameters to be monitored as described in NRC Regulatory Guide 1.127, Revision 2, positions C.5.a through C.5.h. Parameters monitored and inspected for concrete structures shall also follow the guidance of ACI 349.3R and ACI 201.1R, and include cracking, movements, conditions at junctions with abutments and embankments, loss of material, increase in porosity and permeability, seepage, and leakage. Parameters to be monitored and inspected for earthen embankment structures shall include settlement, depressions, sink holes, slope stability, seepage, proper functioning of drainage systems, and degradation of slope protection features. The cool water and intake channels, canals (including submerged canals), intake and discharge structures are monitored for sedimentation, debris, or instability of slopes that may impair the function of the canals under extreme low flow conditions. They are also monitored for other abnormal conditions affecting bank erosion, bed aggregation, degradation, and siltation or any other unusual conditions that might affect operational behavior. Painted or coated areas are examined for signs of distress that could indicate degradation of the underlying material. Bolting within the scope of the program is monitored for loss of material, loose bolts, missing or loose nuts, and other conditions indicative of loss of preload.

The program includes periodic visual inspections to monitor for aging effects. Inspections of concrete structures use techniques consistent with the guidance in ANSI/ASCE 11-90 and incorporates inspection qualifications consistent with ACI 349.3R-96. Inspection intervals are consistent with NRC Regulatory Guide 1.127, Revision 2, and include provisions for increased inspection frequency based on evaluation of observed degradation. Further provisions are provided for performance of special inspections, additional inspections, and increased inspection frequencies, after the occurrence of unusual events such as earthquakes, hurricanes, floods, etc., as well as after identifying abnormal or unusual results from a prior inspection.

The program evaluates raw water and groundwater chemistry that is sampled from a location that is representative of the water in contact with structures within the scope of subsequent license renewal. Indications of groundwater infiltration or through-concrete leakage are assessed for aging effects.

Accessible and submerged areas are monitored for indication of degradation with periodic inspections. Submerged concrete structures may be inspected during periods of low water level, when dewatered, or with divers. The program will require examination of representative samples of the exposed portions of the below-grade concrete when excavated for any reason. The acceptability of inaccessible areas will be evaluated when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.

The program will monitor conditions to identify new or progressive issues and, when practical, project identified degradation for the next scheduled inspection. Collected engineering data will be reviewed to determine if changes fall outside the normal or expected conditions. Trending will be performed of quantitative measurements and qualitative information for findings exceeding acceptance criteria for all applicable parameters monitored or inspected.

The program implements plant specific acceptance criterion based on Chapter 5 of ACI 349.3R to assess the adequacy of observed aging effects and to determine whether further evaluations are necessary. Acceptance criteria for inspections of earthen structures and canals shall ensure these structures are capable of performing their required functions. Loose bolts and nuts, and degradation of piles and sheeting are accepted by engineering evaluation or subject to corrective actions.

The program requires a Condition Report be initiated in the Corrective Action Program whenever non-conforming conditions are found (i.e., the acceptance criteria are not met). The program requires initiation of a Condition Report for conditions of structures or components classified as “acceptable with deficiencies” or “unacceptable” or when design deviations or conditions that may affect the availability of the emergency cooling or flood protection are identified.

When inspection findings indicate that significant changes have occurred, the conditions are to be evaluated. This includes a technical assessment of the causes of distress or abnormal conditions, an evaluation of the behavior or movement of the structure, and recommendations for remedial or mitigating measures. 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.

The structures included within the scope of this program are as follows:

- Intake Pumping Station
- Gate Structure Number 2
- Gate Structure Number 3

- Circulating Water Conduits
- Intake Channel
- Discharge Control Structure
- North Bank of Cool Water Channel East of Gate Structure Number 2
- South Dike of Cool Water Channel Between Gate Structure Numbers 2 and 3

NUREG-2191 Consistency

The enhanced Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program will be consistent with the 10 elements of aging management program XI.S7, Inspection of Water-Control Structures Associated with Nuclear Power Plants, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Revise implementing procedures to add Circulating Water Conduits to the scope of the program.

   Program Element Affected: Element 1 - Scope of Program

2. Ensure preventive actions are included 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, ASTM A490, ASTM F1852 and/or ASTM F2280 bolts, the preventive actions for storage, lubricant selection, and bolting and coating material selection discussed in Section 2 of the Research Council for Structural Connections publication, “Specification for Structural Joints Using High-Strength Bolts,” dated August 2014, will be used.

   Program Element Affected: Element 2 - Preventive Actions

3. Revise implementing procedures for monitoring and inspection of water-control concrete structures to also include those parameters as described in ACI 201.1R, these include cracking, movements (e.g., settlement, heaving, and deflection), conditions at junctions with abutments and embankments, loss of material, increase in porosity and permeability, seepage, and leakage.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

4. Revise implementing procedure to also include monitoring of the cool water and intake channels for sedimentation, debris, or instability of slopes that may impair the function of the canals under extreme low flow conditions.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

5. Revise implementing procedure to include examinations of painted or coated areas for signs of distress that could indicate degradation of the underlying material.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

6. Revise implementing procedure to include monitoring of bolting within the scope of the program for loss of material, loose bolts, missing or loose nuts, and other conditions indicative of loss of preload. In addition, concrete around anchor bolts is monitored for cracking.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

7. Revise implementing procedures to examine representative samples of the exposed portions of the below-grade concrete when excavated for any reason. The acceptability of inaccessible areas will be evaluated when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.

   Program Element Affected: Element 4 - Detection of Aging Effects

8. Revise implementing procedures to ensure indications of groundwater infiltration or through-concrete leakage are assessed for aging effects. This may include engineering evaluation, more frequent inspections, or destructive testing of affected concrete to validate existing concrete properties, including concrete pH levels. When leakage volumes allow, assessments may include analysis of the leakage pH, along with mineral, chloride, sulfate and iron content in the water.

   Program Element Affected: Element 4 - Detection of Aging Effects

9. Revise implementing procedures to ensure submerged areas are monitored for indication of degradation with periodic inspections performed at intervals in accordance with the guidance in NRC Regulatory Guide 1.127 Revision 2. Submerged concrete structures may be inspected during periods of low tide, when dewatered, or with divers.

   Program Element Affected: Element 4 - Detection of Aging Effects

10. Ensure NRC Information Notice 2011-20, “Concrete Degradation by Alkali-Silica Reaction (ASR),” is referenced and add additional guidance for concrete inspections to identify indications of the presence of ASR. The additional guidance for these inspections of reinforced concrete, each inspection interval, include examination for pattern cracking with darkened crack edges, water ingress, and misalignment inspections. These inspection results will be evaluated by the responsible engineer each inspection cycle to identify changes that could be indicative of aging effects caused by reaction with aggregates. Such indications will be entered into the Corrective Action Program for evaluation.

    Program Element Affected: Element 4 - Detection of Aging Effects

11. Revise implementing procedures to incorporate the guidance of NRC Regulatory Guide 1.127 Revision 2, for the compilation of engineering data collected from aging management program inspections. The use of photographs and surveys for comparison purposes of previous and current conditions as well as review of previous inspection records (baseline) may be used to identify new or progressive issues. Collected engineering data is reviewed by qualified engineering personnel to determine if changes fall outside the normal or expected conditions.

    Program Element Affected: Element 5 - Monitoring and Trending

12. Ensure trending to be performed of quantitative measurements and qualitative information is required for findings exceeding acceptance criteria for applicable parameters monitored or inspected.

    Program Element Affected: Element 5 - Monitoring and Trending

13. Revise implementing procedures to require quantitative baseline inspection data to be established in accordance with acceptance criteria prior to the subsequent period of extended operation. Previously performed inspections that were conducted using comparable acceptance criteria will be acceptable in lieu of performing a new baseline inspection.

    Program Element Affected: Element 5 - Monitoring and Trending

14. Revise implementing procedures to require an engineering evaluation or the initiation of a Condition Report in the Corrective Action Program when any structural condition (including loose bolts, nuts, and degradation of piles and sheeting) is classified as “acceptable with deficiencies” or “unacceptable.”

    Program Element Affected: Element 6 - Acceptance Criteria

15. Ensure acceptance criteria for inspections of earthen structures and canals shall ensure no significant loss of material or loss of form or evidence of erosion, settlement, frost action, waves, currents, surface runoff, or seepage, and ensure intake channel sedimentation is within design basis values.

    Program Element Affected: Element 6 - Acceptance Criteria

<u>Operating Experience</u>

The following examples of operating experience provide objective evidence that the Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2023, a program effectiveness review was performed for the Inspection of Water-Control Structures Program described in FSAR Section O.1.34. The purpose of the program effectiveness review was to verify that the existing aging management program activities, to identify and correct, as warranted, age-related degradation of components monitored by the Inspections of the Inspection of Water-Control Structures Program, are being effectively implemented in the initial license renewal period of extended operation. In the initial license renewal period of extended operations, the Maintenance Rule Structural Monitoring Program included implementing activities that inspected and managed the Water-Control Structures aging management program. The program effectiveness review was comprised of a review of inspection implementation activities to date and pertinent issues in the Corrective Action Program, searching for identified age-related degradation of components related to Water-Control Structures. The program manages the effects of aging on the BFN Intake Pumping Station, Gate Structure Number. 2, Gate Structure Number 3, Intake Channel, Discharge Control Station, North Bank of Cool Water Channel East of Gate Structure Number 2, and South Dike of Cool Water Channel Between Gate Structure Numbers 2 and 3 that are within the scope of 10 CFR 54.4, Requirements for Renewal of Operating License for Nuclear Power Plants. A review of the inspection results and issues in the Corrective Action Program from 2013 through 2022 determined that degradation was identified and documented, and conditions were evaluated. The review found that only minor degradation, such as concrete spalling and cracking, steel corrosion, and roof leaks, were identified. Age-related issues were evaluated and corrected under the Corrective Action Program resulting in effective implementation of this aging management program.

   This operating experience provides objective evidence that the inspections, maintenance practices, use of operating experience, and the Corrective Action Program effectively monitor the condition of water-control structures to assure that water-control structures will be able to continue to perform their intended functions and that appropriate aging management program activities will be performed during the subsequent period of extended operation.

2. The effectiveness review looked at the results of Inspection of Water-Control Structures program inspections. In 2014, during cooling tower operation with Unit 2 and Unit 3 in helper mode, Operations was not able to maintain cold water channel below the required level of 562 feet and 8 inches elevation. During this time there were 10 cooling tower lift pumps running. Divers had reported that the cooling water discharge diffusers were 59% plugged.

Operations prepared to remove Unit 3 from cooling towers to gain control of cold-water channel level. During the process of removing Unit 3 from cooling towers, one of the cooling tower vacuum breakers opened causing vacuum to lower rapidly. This, in conjunction with the plugged diffusers, resulted in overflowing Gate Structure Number 2 while transitioning Unit 3 to open mode. Following the event, the Discharge Control Structure was inspected as documented in the Corrective Action Program. The inspection looked for cracking, spalling, exposed reinforcement, and other signs of degradation. No defects were observed. In 2017, the Intake Structure retaining walls, concrete structures and earthen structures were inspected, with acceptable results. Also in 2017, Gate Structure Number 2 inspections of the region of the metal sheet piles that are subject to wetting and drying due to the fluctuating river elevations, were performed. This inspection included both visual inspection and ultrasonic test wall thickness measurements. All results were acceptable. In 2020, the Intake Channel was inspected with acceptable results. Also, in 2020, the North Bank Cooling Water Chanel was inspected with acceptable results.

This example provides objective evidence that the current Inspection of Water-Control Structures program is being effectively implemented to manage aging effects. Continued implementation of the Inspection of Water-Control Structures program will assure that the components within the scope of the program will continue to perform their intended functions during the subsequent period of extended operation.

3. A review of Aging Management Program implementing inspections and activities as part of this effectiveness review identified 2 issues.
    - The first issue was originally identified in 2012 during the conduct of Maintenance Rule Inspections. In 2015, during license renewal inspection of Gate Structure Number 3, a missing bottom bolt on the northernmost beam which helps support the eastern concrete machinery deck between Cell 12 and Cell 13 was identified. This issue was discussed in an engineering calculation which documents Maintenance Rule and License Renewal Inspections for the period from 2013 to 2017. This calculation documents an engineering evaluation from 2012 which determined that the northernmost beam does not carry any loading from the machinery on the slab above. This beam and its connections are designed based on the design of 2 other beams which carry the machinery loads. The missing bolt was judged to not affect the beam's ability to perform its design function. The missing bolt was to be replaced by maintenance activities initiated in 2012. The associated Work Order (WO) was placed in a planning status on October 1, 2012, and currently remains in a planning status.
    - The second issue was originally identified in 2016 as a result of inspection of the South Dike between Gate 2 and 3. Inspection identified excessive vegetation including the growth of mature trees. The issue was entered into the Corrective Action Program. Corrective actions resulted in the initiation of two maintenance WOs. One WO was to spray and/or remove vegetation. This WO was completed. The second WO was to remove the mature trees. The WO was placed in a planning status on May 1, 2018, and currently remains in a planning status. No evaluation of the long term effects of the mature trees on the acceptability of the monitoring interval was documented.

The issue of deficient inspection results not worked in a timely manner is a Work Control Scheduling - Work Prioritization issue affecting multiple aging management programs and is not specific to this aging management program. The issue has been entered into the Corrective Action Program This has resulted in corrective actions to determine a method for the prioritization of aging management related WOs, a method for notification of aging management owners of WO delays or cancellation, and the use of aging management trend codes to aide in tracking aging management issues. These actions have been completed.

The issue of improving documentation of acceptable monitoring / inspection intervals has been entered into the Corrective Action Program. This has resulted in actions, which have been completed, to provide clarity in the following areas of the Civil Design Open Defects Database: Documentation of acceptable monitoring / inspection interval; Recommended time element for repairs - noting elevation of concern time period as required; Ensuring defects are aligned with corrective action process; and Ensuring defects are classified in accordance with plant procedures as “Acceptable,” “Acceptable with Deficiencies,” or “Un-Acceptable.” These items will address any new and existing items in Open Defects Database. Additionally, the associated plant procedure was updated to require all future defects identified address these items when added to Open Defects Database.

These examples provide objective evidence that the Water-Control Structures aging management inspections are capable of detecting damage to in-scope components and other indications of possible age-related degradation. This example also demonstrates that deficiencies, including those found during program assessments, are entered into the Corrective Action Program and actions are taken to evaluate and address deficiencies accordance with the Inspection of Water-Control Structures aging management program and the Corrective Action Program.

4. There have been two self-assessments associated with the BFN License Renewal programs during the period of extended operation:

   - BFN 2020 License Renewal Self-Assessment. This assessment identified one learning opportunity and one potential deficiency associated with the Inspection of Water-Control Structures program.

     A Learning opportunity was identified that an engineering calculation which documents that the initial License Renewal inspection of the Intake Channel during the Period of Extended Operation was conducting by only a walkdown, and no issues were identified. A walkdown was determined to be inappropriate for this inspection. The learning opportunity also stated that the License Renewal inspection of the Intake Channel should include a review of topography surveys which are performed on a five-year periodicity. The topography reports provide information to identify changes in the contours, (depth and shape) of the Intake Channel by comparing the as found contours to the original design contours. This issue was entered into the Corrective Action Program. Corrective actions resulted in the Civil Design Maintenance Rule and License Renewal calculation being revised to include the most recent topographic survey data. In addition, to ensure that the most recent topographic survey data is included in all future calculations every five years, a place keeper has been put in the inspection files for the Intake Channel at five-year increments through 2049 by adding a note on the inspection documents to include the most recent topographic survey data. Also, a file for the topographic survey data has been placed in each Civil Design Maintenance Rule calculation file through 2052.

     The potential deficiency identified, that as a part of the License Renewal process, TVA committed to enhance the Inspection of Water-Control Structures Program to periodically monitor raw water (for pH, chloride, sulfate; at least once every five years) near submerged concrete of the Intake Pumping Station for a possible aggressive environment. In accordance with the Chemistry Program procedure, the results of this periodic monitoring are to be provided to the Inspection of Water-Control Structures Aging Management Program Owner. Although the required raw water sampling is being performed by Chemistry, no evidence has been found that this data has ever been transmitted to Civil Design Engineering Aging Management Program Owner for assessment and monitoring of the submerged Intake Pumping Station concrete. This issue was entered into the Corrective Action Program. The result was that the Civil Design Maintenance Rule and License Renewal calculation was revised to include the review performed by Civil Design Engineering of the latest chemistry parameters provided by BFN Chemistry of the Tennessee River water. In addition, to ensure that Civil Engineering acceptance of the river parameters are included in all future calculations every five years, a place keeper has been put in the inspection files for the south side of the Intake Structure at five year increments through 2049 by adding a note on the inspection documents to include the river parameters and their acceptance by Civil Design. Also, a file for the river parameters has been placed in each Civil Design Maintenance Rule calculation file through 2052.

- BFN Aging Management Program Self-Assessment, conducted in 2022. There were no specific Inspection of Water-Control Structure program technical issues found.

These examples demonstrate that periodic self-assessments of the Inspection of Water-Control Structure aging management program have been performed to identify and correct program elements that need improvement to maintain the quality performance of the program.

Conclusion

The enhanced Inspection of Water-Control Structures Associated with Nuclear Power Plants aging management program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.35 Protective Coating Monitoring and Maintenance

Program Description

The BFN Protective Coating Monitoring and Maintenance aging management program is a new program that ensures monitoring and maintenance of Service Level 1 coatings is implemented in accordance with Position C.4 of NRC Regulatory Guide 1.54, “Service Level I, II, IIII, and In-Scope License Renewal Protective Coatings Applied to Nuclear Power Plants,” Revision 3, for the subsequent period of extended operation. These coatings are not credited for managing the effects of corrosion for the carbon steel containment shells 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 (ECCS) suction strainers. Degraded coatings in the containment are assessed periodically to ensure post-accident operability of the ECCS.

Regulatory Position C.4 in NRC Regulatory Guide 1.54 Revision 3 describes an acceptable technical basis for a Service Level I coatings monitoring and maintenance program. ASTM D 5163-08 and later endorsed years of the standard in NRC Regulatory Guide 1.54 Revision 3 are acceptable and considered consistent with NUREG-2191 Section XI.S8. The BFN program will conform to ASTM D 5163-08.

The program will use the aging management detection methods, inspector qualifications, inspection frequency, monitoring, trending, and acceptance criteria defined in ASTM D 5163-08, and inspects for any visible defects, such as blistering, crazing, cracking, flaking, peeling, rusting, and physical damage. The inspection interval is no greater than every two years. The inspection report prioritizes repair areas as either needing repair during the same outage or as postponed to future outages, but under surveillance in the interim period. The assessment from periodic inspections and analysis of total amount of degraded or unqualified coatings in the containment is compared with the total amount of permitted degraded or unqualified coatings to provide reasonable assurance of ECCS operability.

The new BFN Coating Monitoring and Maintenance AMP will include additional training and qualifications for specialist, inspectors and coating applicators in conformance with NRC Regulatory Guide 1.54, Rev 3, position C.3.

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 program requires visual inspection and maintenance of Service Level I protective coatings both in atmospheric and immersion service and of the ECCS suction strainers. In addition, when the Torus is drained, the program will be used for inspection of normally submerged levels of the Torus, including the ECCS suction strainers.

<u>NUREG-2191 Consistency</u>

The Protective Coating Monitoring and Maintenance aging management program will be consistent with the 10 elements of aging management program XI.S8, Protective Coating Monitoring and Maintenance, specified in NUREG-2191.

<u>Exceptions to NUREG-2191</u>

None.

<u>Enhancements</u>

None.

<u>Operating Experience</u>

The following examples of operating experience provide objective evidence that the Protective Coating Monitoring and Maintenance program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In March 2011, surface corrosion (rust) was observed during the Maintenance Rule walkdown in the Unit 2 Steam Jet Air Ejector 'B' Room performed during the Unit 2 refueling outage, U2R16. A work order was written to have the surface corrosion removed and new coatings applied during the U2R17 outage. Corrosion was identified primarily on pipe supports, duct, Steam Jet Air Ejector(s), and structural steel. An evaluation determined that structural integrity of the identified items was not challenged.

   This is an example of effective identification of degraded conditions and evaluations.

2. In October 2012, during the Unit 1 refueling outage U1R9 torus exterior coating inspection, multiple indications of light rust, no coating, minor scratches, and chips to base metal in accessible areas plus flaking on main vent lines were identified. There were also a significant

number of patches of coating loss to base metal on the torus and ring header. These indications were considered typical of aging-related coating degradation. They did not indicate situations which would impair the ability of the torus, ring header, or supports to perform their intended function until the next Unit 1 refueling outage, U1R10. Pre-emptive action to re-coat/touch-up impaired coating areas was warranted to prevent unacceptable consequences of this aging management issue. As input for this Service Request, the originator (the site protective coating engineer) reviewed past work orders in place to perform similar work for the torus exterior. A work order for the repairs was subsequently completed.

This is an example of effective identification of degraded conditions and implementation of appropriate corrective measures.

3. In April 2019, during performance of a general visual examination, areas of light to heavy rust and loss of protective coatings were observed throughout the vent header of Unit 2. Rust was present in areas where protective coatings were damaged. An evaluation of this inspection report was performed by the Corporate Coatings Program Engineer in communication to the Site Coatings Program Engineer. The site engineer had reviewed the results during the outage and determined no actions needed to be taken. As noted in the report, there were no significant changes to conditions identified during previous examinations. The coating system used a two-coat system, with the first coat being an inorganic zinc. This first coating layer is primarily relied on for corrosion control. The second coating layer, where some material was identified to be scrapped off, is more for appearance, but does have a lesser corrosion control function. Based on the risk involved in re-coating these areas because of their location, it was determined that there was no immediate need to re-coat the affected areas. A Condition Report was created based on inspection findings, and based on the associated evaluation, no further actions were determined to be necessary.

   This is an example of effective identification of degraded conditions, evaluation and implementation of appropriate corrective measures.

4. In March 2018, coating defects were identified by divers when doing the immersion coating inspection in the torus during Unit 3 refueling outage U3R18. All defects were repaired and operability was maintained.

   This is an example of effective identification of degraded conditions and implementation of appropriate corrective measures.

5. In December 2018, when the Unit 1 torus exterior was inspected, damage to coatings was identified. A work order was generated, which included a contingency for repair. Upon review of the damage, the repair was made. A Condition Report was also initiated to capture the condition in the Corrective Action Program.

   This is an example of effective implementation of corrective measures being taken and trending of the issue.

Conclusion

The new Protective Coating Monitoring and Maintenance program will provide reasonable assurance that the identified aging effects are adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.36 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The Electrical Insulation for Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program is an existing condition monitoring program that manages the effects of reduced insulation resistance of the electrical insulation for license renewal in-scope, non-environmentally qualified, electrical cables and connections during the subsequent period of extended operation.

In most areas of BFN, the actual ambient environments (e.g., temperature, radiation, or moisture) are less severe than the plant design basis environment. In a limited number of adverse localized environments in the plant, the operating environment is significantly more severe than the design basis environment. Electrical insulation used in electrical cables and connections located in adverse localized environments may degrade more rapidly or have adverse effect on operability.

Accessible cables and connections located in adverse localized environments are managed by visual inspection. These cables and connections are visually inspected at least once every 10 years for cable jacket and connection insulation surface anomalies, such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination that could indicate incipient conductor insulation aging degradation from temperature, radiation, or moisture. This is an adequate inspection frequency to preclude failure of the cable and connection insulation since experience shows that aging degradation is a slow process.

Electrical insulation material for cables and connections previously identified and dispositioned during the first period of extended operation as subjected to an adverse localized environment are evaluated for cumulative aging effects during the subsequent period of extended operation. If an unacceptable condition or situation is identified for cable or connection electrical insulation by visual inspection or test, corrective actions are taken including a determination as to whether the same condition or situation is applicable to other in-scope accessible and inaccessible cable or connection electrical insulation (e.g., extent of condition).

Age-related degradation observed during the inspection process is addressed by the initiation of a Condition Report (CR) in accordance with the Corrective Action Program. If an unacceptable condition or situation is identified for a cable or connection in the inspection sample, an evaluation will determine if the same condition or situation is applicable to other accessible or inaccessible cables or connections. Additional inspections, repairs, or replacements are initiated as appropriate under the Corrective Action Program. If visual inspections identify degraded or damaged conditions that may impact the cable system's ability to perform its intended functions, then testing may be performed for evaluation. Testing may include thermography and one or more proven condition monitoring test methods applicable to the cable and connection insulation material. Testing as part of an existing maintenance, calibration or surveillance program may be credited. Electrical cable and connection insulation material test results are to be within the acceptance criteria, as identified in BFN procedures. For a large number of cables and connections identified as potentially degraded, a sample population is tested. The first inspection for subsequent license renewal is to be completed prior to the subsequent period of extended operation.

<u>NUREG-2191 Consistency</u>

The enhanced Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be consistent with the 10 elements of aging management program XI.E1, Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements, specified in NUREG-2191.

<u>Exceptions to NUREG-2191</u>

None.

<u>Enhancements</u>

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Revise the implementing procedures to require review of plant-specific OE for previously identified and mitigated adverse localized environments cumulative aging effects applicable to in-scope cable and connection electrical insulation.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

2. Revise the implementing procedures to require inspections for adverse localized environments for each of the most limiting cable and connection electrical insulation plant environments (e.g., caused by temperature, radiation, moisture, or contamination).

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

3. Revise the implementing procedures to require, during inspections, that cable and connection insulation be evaluated to confirm that aging related dispositioned corrective actions continue to support in-scope cable and connection intended functions during the subsequent period of extended operation.

   Program Element Affected: Element 4 - Detection of Aging Effects

4. Revise the implementing procedures to require the first inspection for subsequent license renewal to be completed prior to the subsequent period of operation.

   Program Element Affected: Element 4 - Detection of Aging Effects

5. Revise the implementing procedures to require that if visual inspections identify degraded or damaged conditions, then testing may be performed for evaluation. For a large number of cables and connections identified as potentially degraded, a sample population is tested. The factors to be considered in the development of the cable and connection insulation sample representing approximately 20% of the in-scope population include: environment including identified adverse localized environments (high temperature, high humidity, vibration, etc.), voltage level, circuit loading, connection type, location, and insulation material. Additionally, the component sampling methodology will utilize a population that includes a representative sample of in-scope electrical cable and connection types regardless of whether or not the component was included in a previous aging management or maintenance program. The technical basis for the sample selection will be required to be documented.

   Program Element Affected: Element 4 - Detection of Aging Effects

6. Revise the implementing procedures to ensure acceptance criteria are met by conducting a review of test results or findings of surveillances of in-scope components.

   Program Element Affected: Element 6 - Acceptance Criteria

7. Revise the implementing procedures to allow cable system testing, in accordance with applicable TVA procedures, as an alternative means for testing if visual inspections does not meet acceptance criteria.

   Program Element Affected: Element 6 - Acceptance Criteria

8. Revise the implementing procedures to require, when an unacceptable condition is identified, an evaluation to be performed to demonstrate that the condition will not adversely affect the affected component's ability to perform it's associated intended function for the time period being considered. The evaluation, including the technical basis, shall be documented.

   Program Element Affected: Element 7 - Corrective Actions

9. Revise the implementing procedures to require a determination as to whether the same condition or situation is applicable to additional in-scope accessible and inaccessible cables or connections (extent of condition).

   Program Element Affected: Element 7 - Corrective Actions

<u>Operating Experience</u>

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 will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for the Accessible Non-Environmental Qualification Cables and Connections described in FSAR Section O.1.1 in support of preparing the BFN Subsequent License Renewal Application. The purpose of the program effectiveness review was to verify that the intent of the existing aging management program activities, to identify and correct, as warranted, age-related degradation of electrical insulation for electrical cables and connections, is being effectively implemented in the initial license renewal period of extended operation. The original activities included identification of adverse localized environments (ALE), visual inspection of electrical insulation for accessible cables and connections, documentation of findings, and follow-up actions in the Corrective Action Program. The program effectiveness review was comprised of a review of visual inspection implementation activities to date and pertinent issues in the Corrective Action Program, searching for identified age-related degradation of electrical insulation for electrical cables and connections. Pre-period of extended operation, visual inspection results, and resulting issues in the Corrective Action Program, from the initial License Renewal inspections were reviewed. The reviews did not identify significant age-related degradation of electrical insulation for accessible electrical cables and connections that impacted the ability to perform intended functions. Only minor degradation of cable jackets that would not impact performance of intended functions was observed. In some ALEs, there were no observable conditions or changes for the electrical cable and connection insulation exposed to the ALE. There were no issues in either the pre-period of extended operation implementation or the current period of extended operation related operating experience items, where an in-scope cable was unable to perform its intended function due to age-related degradation.

   This operating experience provides objective evidence that the visual inspections effectively monitor electrical insulation for electrical cables and connections to assure that they will be able to continue to perform their intended functions and that appropriate aging management will be performed during the subsequent period of extended operation.

2. During the program effectiveness review, it was identified that the first visual inspections after entry into the period of extended operation had been scheduled to be performed later than

required by the program. The program procedure requires visual inspection of in-scope cables and connectors to be commenced prior to the expiration of the initial 40-year license for each unit and will be conducted every ten years thereafter throughout the period of extended operation. The initial inspections were completed as required, however the Periodic Maintenance data base incorrectly started the ten year clock at the date of entry into the period of extended operation, as opposed to the date of the previous inspection. This issue was entered into the Corrective Action Program and corrective actions have taken to schedule and complete the visual inspections as soon as practical. Unit 1 and 2 outage area inspections, and Unit 1, 2, and 3 non-outage area inspections are complete. Unit 3 outage area inspections will be performed in the Spring of 2024. During the inspections performed to date, there were no indications of cable degradation identified. Some indications of heat degraded flexible conduit and junction boxes were identified, and these conditions were entered into the Corrective Action Program. The inspections performed to date indicate that the cables in the program are generally in excellent shape.

This operating experience provides objective evidence that the visual inspections and the Corrective Action Program effectively monitor electrical insulation for electrical cables and connections to assure that they will be able to continue to perform their intended functions and that appropriate aging management will be performed during the subsequent period of extended operation.

3. During the program effectiveness review, a review of Condition Reports identified that cable jacket damage involving cracking, flaking, and frayed cable jacket and insulation between the junction box and the Amphenol connector of the directional control valve (DCV) on the CRD System Hydraulic Control Units (HCUs) had been identified on all three BFN units. This condition was documented in October 2015, and again in December 2017. These cables are in a mild environment and do not have a License Renewal intended function, however no evaluation was conducted to determine if a new form if aging was involved which could be applicable to cables and connectors that are in-scope. This condition was entered into the Corrective Action Program and as a result, a conservative decision was made by the cable program owner to include these cables in the Accessible Non-Environmental Qualification Cable and Connections program. An evaluation of the cable jacket degradation determined the condition is due to mechanical damage which is a occurring as a result of the manipulation of the cables during clearance activities. Each time a CRD System HCU is placed under clearance, these cables are disconnected and physically restrained. This manipulation for clearances was determined to be the cause of the jacket damage, however no damage was found on the underlying wires or insulation. No new aging mechanism applicable to in-scope cables was identified.

   This operating experience provides objective evidence that the Corrective Action Program will evaluate not in-scope cable degradation to identify for possible new aging mechanisms, to assure that in-scope cables and connections will be able to continue to perform their intended functions and that appropriate aging management will be performed during the subsequent period of extended operation.

4. An Emergency Diesel Generator (EDG) vulnerability review was held in August 2015. During the review, it was recommended that the BFN EDG generator leads be inspected to address potential vulnerability due to aging and handling of the leads over time. Work orders for visual inspections of the EDG generator leads were created and completed with no indications of degradation identified.

   This operating experience provides objective evidence that the use of “system health reviews” (i.e., EDG vulnerability review) and the Corrective Action Program to detect aging-related degradation is occurring and being used to take appropriate actions to correct identified degradation.

Conclusion

The enhanced Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will provide reasonable assurance that the identified aging effects of insulation for electrical cables and connections will be adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.37 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 aging management program is an existing performance monitoring program that manages the effects of reduced insulation resistance of non-environmentally qualified cable and connection electrical insulation in instrumentation circuits with sensitive, high-voltage, low-level current signals. The program applies to the in-scope portions of the Neutron Monitoring System and the Radiation Monitoring System (not managed by the Environmental Qualification of Electric Equipment program (B.3.1.3)) that are subjected to adverse localized environments caused by temperature, radiation, or moisture.

In most areas of BFN, the actual ambient environments (e.g., temperature, radiation, or moisture) are less severe than the plant design basis environment. In a limited number of adverse localized environments in the plant, the operating environment is significantly more severe than the design basis environment. Electrical insulation used in electrical cables and connections located in adverse localized environments may degrade more rapidly or have adverse effect on operability.

This program requires that specific calibration, surveillances, or testing be performed. This testing verifies the material condition of electrical insulation used in instrumentation cables and connections located in adverse localized environments that are within the scope of subsequent license renewal.

BFN performs reviews of calibration results or findings of surveillance programs to ensure that tested components can perform their intended functions and to provide early indication of age related degradation that may adversely impact performance prior to loss of function.

Calibration, surveillance, and testing results that do not meet acceptance criteria are entered into the corrective action process for evaluation and resolution and are reviewed for aging effects when the results are available. The first reviews of calibration, surveillance, and testing results will be completed prior to the subsequent period of extended operation and at least every 10 years thereafter.

Age-related degradation observed during calibration, surveillance, or testing is addressed by the initiation of a Condition Report in accordance with the Corrective Action Program. If an unacceptable condition or situation is identified for a cable or connection, an evaluation will determine if the same condition or situation is applicable to other similar cables or connections. Additional testing, repairs, or replacements are initiated as appropriate under the Corrective Action Program. Testing may include one or more proven condition monitoring test methods applicable to the cable and connection insulation material. Electrical cable and connection insulation material test results are to be within acceptance criteria, as identified in BFN procedures.

NUREG-2191 Consistency

The enhanced Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits aging management program will be consistent with the 10 elements of aging management program XI.E2, Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Revise the implementing procedures to include the in-scope portions of the Radiation Monitoring System listed in BFN SLRA Subsection 2.3.3.37.

   Program Element Affected: Element 1 - Scope of Program

2. Revise implementing procedures to include documented reviews of plant-specific OE for previously identified and mitigated adverse localized environments cumulative aging effects applicable to in-scope cable and connection electrical insulation.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

3. Revise implementing procedures to include documented inspections for adverse localized environments for each of the most limiting cable and connection electrical insulation plant environments (e.g., caused by temperature, radiation, moisture, or contamination).

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

4. Revise the implementing procedures to include documentation of reviews of calibration, surveillance, and test results for the components within the scope of the program.

   Program Element Affected: Element 4 - Detection of Aging Effects

5. Revise the implementing procedures to include performance of cable tests for the components within the scope of the program when the calibration or surveillance program does not include the cabling system in the testing circuit, or as an alternative to the review of calibration results.

   Program Element Affected: Element 4 - Detection of Aging Effects

6. Revise implementing procedures to require trending of inspection and test results that are trendable and provide additional information on the rate of cable or connection degradation when age related degradation is suspected or found.

   Program Element Affected: Element 5 - Monitoring and Trending

7. Revise implementing procedures to ensure acceptance criteria are met by conducting a review of calibration results or findings of surveillances of in-scope components prior to the subsequent period of extended operation and at least once every 10 years.

   Program Element Affected: Element 6 - Acceptance Criteria

8. Revise implementing procedures to allow cable system testing, in accordance with applicable TVA procedures, as an alternative means for testing if there is cable degradation when a calibration does not meet acceptance criteria.

   Program Element Affected: Element 6 - Acceptance Criteria

<u>Operating Experience</u>

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 will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for the Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used In Instrumentation Circuits described in FSAR Section O.1.2 in support of preparing the BFN Subsequent License Renewal Application. The purpose of the program effectiveness review was to verify that the intent of the existing aging management program activities, to identify and correct, as warranted, age-related degradation of electrical insulation for electrical cables used in instrumentation circuits, is being effectively implemented in the initial license renewal period of extended operation. The original activities included a report to provide a conclusion about the condition of the Intermediate Range Monitor and Local Power Range Monitor cable systems. This report utilizes the system calibration and signal integrity testing performed on the systems. The initial report was conducted prior to entering the period of extended operation. The program effectiveness review was comprised of Intermediate Range Monitor/Local Power Range Monitor testing conducted during operation and during outages, a review of Condition Reports (CRs) and Work Orders (WOs) for identified issues, and the cable condition report performed prior to period of extended operation. The reviews did not identify significant age-related degradation of electrical insulation for accessible electrical cables and connections that impacted the ability to perform intended functions. Degradation was detected in individual nuclear instruments, but did not render the system incapable of performing its intended function. Appropriate WOs were initiated to correct any identified conditions and allowed the individual instruments to return to service.

   This operating experience provides objective evidence that evaluation and testing activities taken as part of the Electrical Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements Used In Instrumentation Circuits Program to assure that in-scope components will be able to continue to perform their intended functions and that appropriate aging management will be performed during the subsequent period of extended operation.

2. During the program effectiveness review, it was identified that the first cable condition report after period of extended operation had been scheduled to be performed later than required by the program. This issue was entered into the Corrective Action Program and corrective action was taken to schedule the report as soon as practical. Corrective actions have been completed and the reports for all BFN units have been performed. The reports did not identify significant age-related degradation of electrical insulation for accessible electrical cables and connections that impacted the ability to perform intended functions. Although the first report in the period of extended operation is delayed, there will still be two reports in the period of

extended operation, and the delay did not lead to undetected degradation causing loss of intended function.

This operating experience provides objective evidence that program evaluations are used to identify deficient conditions in the program, and for the Corrective Action program to correct those conditions, to assure that in-scope electrical insulation for electrical cables used in instrumentation circuits will be able to continue to perform their intended functions and that appropriate aging management will be performed during the subsequent period of extended operation.

3. A CR in the Corrective Action Program documents an evaluation for a reactor shutdown caused by Intermediate Range Monitor noise during a reactor startup, which occurred on October 1, 2019. The evaluation reviewed past noise events on the Intermediate Range Monitor detectors and actions that have been taken to address the history of noise issues. The report documented that the actions being taken are appropriate and recommended additional actions to be taken. The CR documented actions to address these additional recommendations.

   This operating experience provides objective evidence that plant event evaluations are used to identify improvement opportunities, and for the Corrective Action program to develop and implement corrective actions, to assure that in-scope electrical insulation for electrical cables used in instrumentation circuits will be able to continue to perform their intended functions and that appropriate aging management will be performed during the subsequent period of extended operation.

4. A system vulnerability review was conducted in January 2021. The scope of the review consisted of noise intrusion into the Intermediate Range Monitor circuit and shielding of the Intermediate Range Monitor cables from the Intermediate Range Monitor detector to the including connectors and back to the Intermediate Range Monitor drawers in the Main Control Room for all eight Intermediate Range Monitors per unit. The review evaluated past BFN operating experience, industry operating experience, and current maintenance and testing practices. Corrective actions were developed from the vulnerability review, were entered into the Corrective Action Program, and implemented.

   This operating experience provides objective evidence that BFN and industry operating experiences are used to identify improvement opportunities, and for the Corrective Action program to develop and implement corrective actions, to assure that in-scope electrical insulation for electrical cables used in instrumentation circuits will be able to continue to perform their intended functions and that appropriate aging management will be performed during the subsequent period of extended operation.

<u>Conclusion</u>

The enhanced Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program will provide reasonable assurance that the reduced electrical insulation resistance aging effects will be adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.38 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 aging management program is an existing condition monitoring program that will provide reasonable assurance that the intended functions of inaccessible medium-voltage power cables (operating voltages of 2 kV to 35 kV) that are not subject to the environmental qualification requirements of 10 CFR 50.49 are maintained consistent with the current licensing basis through the subsequent period of extended operation. This program applies to all inaccessible or underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) medium-voltage cables that are within the scope of subsequent license renewal and potentially exposed to wetting or submergence (i.e., significant moisture). Inaccessible medium-voltage cables designed for continuous wetting or submergence are also included in this program for a one-time inspection and test.

Periodic inspections are conducted to prevent inaccessible medium-voltage power cables from being exposed to significant moisture. Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period) that, if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that results from event driven occurrences and is mitigated by either automatic or passive drains is not considered significant moisture for this program.

The inspection frequency for water accumulation is established and performed based on plant-specific operating experience (OE) over time with cable wetting or submergence. Inspections are performed periodically based on water accumulation over time. The periodic inspection occurs at least once annually with the first inspection for subsequent license renewal completed prior to the subsequent period of extended operation. Inspection frequencies are adjusted based on inspection results including plant-specific OE but with a minimum inspection frequency of at least once annually.

Inspections for water accumulation are also performed after event driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding. Plant-specific parameters are established for the initiation of an event driven inspection. Inspections include direct indication that cables are not wetted or submerged, and that cable/splices and cable support structures are intact.

Dewatering systems (e.g., sump pumps and passive drains) are inspected, and their operation verified periodically. The periodic inspection includes documentation that either automatic or passive drainage systems or manually pumping are effective in preventing cable exposure to significant moisture. Cable testing and manhole inspection results that do not meet the acceptance criteria are evaluated in the Corrective Action Program.

In addition to the above periodic actions, in-scope inaccessible medium-voltage power cables exposed to significant moisture are tested to determine the condition of the electrical insulation. One or more tests may be required based on cable application, construction, and electrical insulation material to determine the age-related degradation of the cable. Cable testing as part of an existing maintenance or surveillance program, with justification, can be credited in lieu of, or in combination with, testing recommended in this program. A BFN-specific inaccessible medium-voltage cable test matrix that documents inspection methods, test methods, and acceptance criteria for in-scope inaccessible medium-voltage power cables will be developed based on OE. Test frequencies are adjusted based on test results (including trending of aging degradation where applicable) and plant-specific OE. Cable testing will occur at least once every 6 years. The first tests for license renewal will be completed prior to the subsequent period of extended operation with additional tests performed at least once every 6 years thereafter.

NUREG-2191 Consistency

The enhanced Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be consistent with the 10 elements of aging management program XI.E3A, Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Revise implementing procedures to specifically include splices present in medium-voltage cables in the scope of this aging management program.

   Program Element Affected: Element 1 - Scope of Program

2. Revise implementing procedures to require the performance of a one-time inspection and test of submarine or other cables designed for continuous wetting or submergence. Additional periodic tests and inspections for these cables will be determined by the one-time test/inspection results as well as industry and plant-specific OE.

   Program Element Affected: Element 1 - Scope of Program

3. Revise implementing procedures to require the inspection frequency for water accumulation to be established and adjusted based on plant-specific OE with cable wetting or submergence. The inspections are performed periodically based on water accumulation over time.

   Program Element Affected: Element 2 - Preventative Actions

4. Revise implementing procedures to require the inspections for water accumulation to be performed after event driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding.

   Program Element Affected: Element 2 - Preventative Actions

5. Revise implementing procedures to require dewatering systems (e.g., sump pumps and passive drains to be inspected and their operation verified periodically (annually). The periodic inspection will include documentation that either automatic or passive drainage systems or manually pumping are effective in preventing cable exposure to significant moisture.

   Program Element Affected: Element 2 – Preventative Actions

6. Revise implementing procedures to require that if water is found during inspection for water accumulation, the condition will be entered in the Corrective Action Program. The Corrective

Action Program will specify and document the completion of actions taken to keep the cables free from significant moisture and to assess cable degradation.

Program Element Affected: Element 2 – Preventative Actions

7. Revise implementing procedures to require the first cable tests to be completed prior to the subsequent period of extended operation with additional tests to be performed at least once every 6 years thereafter.

Program Element Affected: Element 4 - Detection of Aging Effects

8. Revise implementing procedures to require a BFN-specific inaccessible medium-voltage cable test matrix that documents inspection methods, test methods, and acceptance criteria for in-scope inaccessible medium-voltage power cables to be developed based on OE.

Program Element Affected: Element 4 - Detection of Aging Effects

9. Revise implementing procedures to require visual inspections to be performed each time with the same inspection requirements (i.e., location, the manner inspected, etc.) such that the results can be compared to previous results for both immediate condition and long-term trend determinations.

Program Element Affected: Element 5 - Monitoring and Trending

10. Revise implementing procedures to require test results and associated trends to be evaluated against acceptance criteria to confirm that the timing of subsequent inspections and testing will maintain the components' intended functions throughout the subsequent period of extended operation based on the projected rate of degradation.

Program Element Affected: Element 5 - Monitoring and Trending

<u>Operating Experience</u>

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 will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Program described in FSAR Section O.1.3 in support of preparing the BFN Subsequent License Renewal Application. The purpose of the program effectiveness review was to verify that the management of degradation of medium voltage power cables connected to the Residual Heat Removal Service Water (RHRSW) pumps are being effectively implemented in the initial license renewal period of extended operation. The original activities included testing of cables included in the program, and monitoring for water intrusion in locations where in-scope cables are located. The program effectiveness review was comprised of a review of testing results for in-scope cables and review of the inspections results of manholes and handholes containing in-scope cables. The cable tests have been completed on a five year rotating basis and the water intrusion inspections are performed on a six month basis. The cable tests did not identify age-related degradation of in-scope cables that impacted the ability to perform intended functions. Inspections of the required manholes and handholes identified repeated issues with wet cables and were entered into the Corrective Action Program. The issues were eventually corrected with a combination of better maintenance and plant modifications. No cable degradation caused by the cables being wet were identified.

   This operating experience provides objective evidence that inspection and testing activities taken as part of the Inaccessible Medium Voltage Cables, Not Subject to 10 CFR 50.49

Environmental Qualification Program along with the Corrective Action Program will assure that in-scope cables and connectors will be able to continue to perform their intended functions, and that appropriate aging management will be performed during the subsequent period of extended operation.

2. TVA Corporate Engineering conducted a self-assessment on the cable program in 2016. The self-assessment utilized cable engineers from all three TVA sites and TVA corporate engineering. Additionally, the EPRI Cable Program Manager was included on the assessment team. The self-assessment identified only administrative issues, which were entered into the Corrective Action Program for resolution. No technical changes to the BFN cable aging management program were required to be made as a result of these issues. TVA Corporate Programs conducted a License Renewal self-assessment in 2020. No program deficiencies related to the cable aging management program were identified as a result of this assessment.

   This operating experience provides objective evidence that BFN, TVA, and industry operating experience are used to identify improvement opportunities, and for the Corrective Action program to develop and implement corrective actions, to assure that in-scope Inaccessible Medium Voltage Cables, Not Subject to 10 CFR 50.49 Environmental Qualification will be able to continue to perform their intended functions and that appropriate aging management will be performed during the subsequent period of extended operation.

3. A Condition Report was initiated to document an NRC violation due to failure to maintain required handholes dry. This failure resulted in the RHRSW cables in the program to be wetted. An Apparent Cause Evaluation was performed and resulted in a plant design change to add supports and straps to the handholes to lift the RHRSW pump cables above the expected high water level. Additionally, maintenance was performed on the sump pumps to improve the reliability. The combination of the repaired sump pumps and the plant modification, the cables have remained dry as documented in the continuing inspections of the handholes. No degradation of the cables due to the wetting was identified.

   This operating experience provides objective evidence that the Corrective Action Program, plant maintenance practices, and plant modifications are used to correct program deficiencies. This provides assurance that in-scope Inaccessible Medium Voltage Cables, Not Subject to 10 CFR 50.49 Environmental Qualification will be able to continue to perform their intended functions and that appropriate aging management will be performed during the subsequent period of extended operation.

4. An Engineering Work Request (EWR) was initiated for the review of NFPA 805 impact on License Renewal. The EWR identifies that when BFN adopted and transitioned to NFPA 805, “Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants,” additional medium voltage inaccessible cables were identified with a License Renewal intended function. Corrective actions were developed to include the identified cables and supporting manhole/handholes into the testing and inspections performed by the program. These actions have been completed.

   This example of the use of the Corrective Action Program provides assurance that in-scope Inaccessible Medium Voltage Cables, Not Subject to 10 CFR 50.49 Environmental Qualification will be able to continue to perform their intended functions and that appropriate aging management will be performed during the subsequent period of extended operation.

<u>Conclusion</u>

The enhanced Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.39 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 aging management program is a new condition monitoring program. The purpose of the program is to provide reasonable assurance that the intended functions of inaccessible or underground instrument and control cables that are not subject to the environmental qualification (EQ) requirements of 10 CFR 50.49 are maintained consistent with the current licensing basis through the subsequent period of extended operation.

This program applies to inaccessible or underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) instrumentation and control cables that are within the scope of subsequent license renewal and potentially exposed to significant moisture. Significant moisture is defined as exposure to moisture that lasts more than three days that if left unmanaged, could potentially lead to a loss of intended function. Cable wetting or submergence that results from event driven occurrences and is mitigated by either automatic or passive drains is not considered significant moisture for the purposes of this program.

When an inaccessible instrument and control cable is exposed to wet, submerged, or other environments for which it was not designed, accelerated age-related degradation of the electrical insulation may occur. The degradation of the cable shield due to water intrusion may introduce electrical ground issues and noise into the circuit.

In this program, periodic actions will be taken to prevent inaccessible instrumentation and control cables from being exposed to significant moisture including inspecting for water accumulation in cable manholes, vaults, conduits, and removing water, as needed. Instrumentation and control cables accessible from manholes, vaults, or other underground raceways will be visually inspected for cable surface abnormalities. Visual inspection frequency will be established and adjusted based on inspection and test results as well as plant-specific and industry Operating Experience (OE). For inaccessible and underground instrumentation and control cables exposed to significant moisture where testing is required, a one-time test will be performed. Visual inspections will occur at least once every six years and may be coordinated with the periodic inspection for water accumulation. The periodic inspections for water will occur at least once annually with the first inspection for subsequent license renewal completed prior to the subsequent period of extended operation. Inspections for water accumulation will also be performed after event-driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding.

In addition to the above periodic actions, in-scope inaccessible and underground instrumentation and control cables subject to significant moisture will be evaluated to determine whether a periodic or one-time test is needed for condition monitoring of the cable insulation system. Initial testing will be performed once on a sample population to determine the condition of the electrical insulation. The following factors will be considered in the development of the electrical insulation sample: temperature, voltage, cable type, and construction including the electrical insulation composition. A sample of 20 percent with a maximum sample of 25 constitutes a representative cable sample size. The basis for the methodology and sample used will be documented. One or more tests may be required due to cable type, application, and electrical insulation to determine the age-related degradation of the cable. Visual inspection will occur at least once every six years and may be coordinated with the periodic inspection for water accumulation. Inaccessible instrumentation and control cables designed for continuous wetting or submergence will also be included. The need for additional tests and inspections will be determined by the test/inspection results as well as industry and plant-specific OE.

Testing of installed in-service inaccessible and underground instrumentation and control cables as part of an existing maintenance, calibration or surveillance program, testing of coupons, abandoned or removed cables, or inaccessible medium- or low-voltage power cables subjected to the same or bounding 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 instrumentation and control cables when testing is recommended in this aging management program.

Dewatering systems (e.g., sump pumps and passive drains) will be inspected, and their operation verified periodically. The periodic inspection will include documentation that either automatic or passive drainage systems or manually pumping are effective in preventing cable exposure to significant moisture. Cable testing and manhole inspection results that do not meet the acceptance criteria will be evaluated in the Corrective Action Program.

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

<u>NUREG-2191 Consistency</u>

The Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be consistent with the 10 elements of aging management program XI.E3B, Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements, specified in NUREG-2191.

<u>Exceptions to NUREG-2191</u>

None.

<u>Enhancements</u>

None.

<u>Operating Experience</u>

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 assuring that intended functions of in-scope cables are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. TVA Corporate Engineering conducted a self-assessment on the cable management program in 2016. The self-assessment utilized cable engineers from all three TVA sites and TVA corporate engineering. Additionally, the EPRI Cable Program Manager was included on the assessment team. The self-assessment identified only administrative issues, which were

entered into the Corrective Action Program for resolution. No technical changes to the BFN cable aging management program were required to be made as a result of these issues. Additionally, TVA Corporate Programs conducted a License Renewal self-assessment in 2020. No program deficiencies related to the cable aging management program were identified as a result of this assessment.

This operating experience provides objective evidence that BFN, TVA, and industry operating experience are used to identify improvement opportunities, and for the Corrective Action program to develop and implement corrective actions, to assure that in-scope Inaccessible Instrument and Control Cables, Not Subject to 10 CFR 50.49 Environmental Qualification will be able to continue to perform their intended functions and that appropriate aging management will be performed during the subsequent period of extended operation.

2. A Condition Report was initiated to document an NRC violation due to failure to maintain required handholes dry. This failure resulted in the RHRSW cables in the program to be wetted. An Apparent Cause Evaluation was performed and resulted in a plant design change to add supports and straps to the handholes to lift the RHRSW pump cables above the expected high water level. Additionally, maintenance was performed on the sump pumps to improve the reliability. The combination of the repaired sump pumps and the plant modification, the cables have remained dry as documented in the continuing inspections of the handholes. No degradation of the cables due to the wetting was identified.

   This operating experience provides objective evidence that the Corrective Action Program, plant maintenance practices, and plant modifications are used to correct program deficiencies. This provides assurance that in-scope cables and connectors will be able to continue to perform their intended functions and that appropriate aging management will be performed during the subsequent period of extended operation.

3. On November 19, 2019, during testing on Unit 3 Source Range Monitor (SRM) C, Instrumentation and Control technicians found that the instruments' extension cable failed to produce a satisfactory testing trace. The technicians identified the need to replace the extension cable. This work was required to be completed while Unit 3 was off-line and the drywell was open. The SRMs provide the operator with information relative to the neutron flux level at very low flux levels in the core. As such, the SRM indication is used by the operator to monitor the approach to criticality and determine when criticality is achieved. The condition was entered into the Corrective Action Program to replace the extension cable and associated connector. The condition was not considered a failure of intended function as there had been no failures of any acceptance criteria steps in the recently completed SRM signal-to-noise testing. The replacement of the extension cable and associated testing was completed and the associated work order was taken to complete status on November 22, 2019.

   Although these specific cables are not in-scope for this aging management program, this operating experience provides objective evidence that the Corrective Action Program, plant maintenance practices, and inspection and testing activities will assure that in-scope cables and connectors will be able to continue to perform their intended functions, and that appropriate aging management will be performed during the subsequent period of extended operation.

4. On June 21, 2015, a Condition Report was initiated as a result of the trip of 2A Reactor Feedwater Pump (RFP) turbine. A work order was written to troubleshoot/repair the cause of the trip. During troubleshooting efforts, shorts were found between conductors in cable 2SG146 as well as intermittent ground. Due to additional cables being in the same conduits, the faulted cables could not be removed from the conduit so that the location of the failure could not be identified. The failed cable was not removed for inspection or forensic analysis. A

design change was completed to replace the cable using a dedicated conduit from inside of the RFP room to the associated pressure switch supported by this cable. The failed section of cable was abandoned in place. The determination was made that the most likely failure mechanism was age degradation of the cable insulation.

Although this specific cable is not in-scope for this aging management program, this operating experience provides objective evidence that the Corrective Action Program, and plant maintenance practices will assure that in-scope cables and connectors will be able to continue to perform their intended functions, and that appropriate aging management will be performed during the subsequent period of extended operation.

Conclusion

The new Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.40 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 aging management program is a new condition monitoring program. Power cables that typically operate at a voltage of less than 1,000V, but no greater than 2kV, and are not subject to the environmental qualification (EQ) requirements of 10 CFR 50.49 are in-scope for this program. In-scope power cables will be maintained consistent with current licensing basis through the subsequent period of extended operation.

All in-scope power cables that are inaccessible or underground (e.g., installed in buried conduit, embedded raceway, cable trenches, cable troughs, duct banks, vaults, manholes, or direct buried installations) and are potentially exposed to significant moisture are covered by this program. This program also includes in-scope power cables that are designed for continuous wetting or submergence. In this program significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period) that if left unmanaged, could potentially lead to a loss of intended function. Significant moisture will not be considered if the cable wetting or submergence is a result of event driven occurrences that are mitigated by either automatic or passive drains.

Low-voltage power cables within-scope of this program that are exposed to wet, submerged, or other environments that they are not designed for are at risk for accelerated age-related degradation of the electrical insulation. The risk contribution due to a failure of a low-voltage power cable may be limited due to system architecture. Common environmental aging stressors, such as submergence, if not anticipated in design or mitigation in-service could influence performing intended functions as well as potential failure of cable insulation.

Periodic actions will be taken to prevent in-scope power cables from being exposed to significant moisture. Inspecting for water accumulation in cable manholes and removing the water as needed is an example of actions that will be taken. In-scope power cables that are accessible from manholes, vaults, or other underground raceways will be visually inspected for cable insulation abnormalities.

The visual inspection frequency for water accumulation in manholes/vaults will be established and adjusted based on plant-specific Operating Experience (OE) with cable wetting or submergence as well as inspection and test results. For inaccessible and underground low-voltage power cables exposed to significant moisture where testing is required, a one-time test will be performed. Visual inspections will occur at least once every six years and may be coordinated with the periodic inspection for water accumulation. The periodic inspections for water will occur at least once annually with the first inspection for subsequent license renewal completed prior to the subsequent period of extended operation. Inspections for water accumulation will also be performed after event-driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding.

In addition, in-scope power cables subject to significant moisture will be evaluated to determine whether a periodic or one-time test is needed for condition monitoring of the cable insulation system. Initial testing will be performed once on a sample population to determine the condition of the electrical insulation. Samples of 20 percent with a maximum of 25 constitute a representative cable sample size. The sample used and the basis for the methodology will be documented. Due to cable type, application, and electrical insulation one or more tests may be required to determine the age-related degradation. Additional tests and inspections will be determined by the results of the tests and inspections, as well as industry and plant-specific OE.

The first cable tests are to be completed prior to the subsequent period of extended operation with additional tests performed at least once every six years thereafter. More frequent testing may be required based on test results (including trending of aging degradation where applicable) and plant specific OE.

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 low-voltage power cables subjected to the same or bounding 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 in this program.

Dewatering systems (e.g., sump pumps and passive drains) will be inspected, and their operation verified periodically. The periodic inspection will include documentation that either automatic or passive drainage systems or manually pumping are effective in preventing cable exposure to significant moisture. Cable testing and manhole inspection results that do not meet the acceptance criteria will be evaluated in the Corrective Action Program.

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

NUREG-2191 Consistency

The Electrical Insulation for Inaccessible Low Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be consistent with the 10 elements of aging management program XI.E3C, Electrical Insulation for Inaccessible Low Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

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 assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. TVA Corporate Engineering conducted a self-assessment on the cable management program in 2016. The self-assessment utilized cable engineers from all three TVA sites and TVA corporate engineering. Additionally, the EPRI Cable Program Manager was included on the assessment team. The self-assessment identified only administrative issues, which were entered into the Corrective Action Program for resolution. No technical changes to the BFN cable aging management program were required to be made as a result of these issues. Additionally, TVA Corporate Programs conducted a License Renewal self-assessment in 2020. No program deficiencies related to the cable aging management program were identified as a result of this assessment.

   This operating experience provides objective evidence that BFN, TVA, and industry operating experience are used to identify improvement opportunities, and for the Corrective Action program to develop and implement corrective actions, to assure that in-scope Low-Voltage Power Cables, Not Subject to 10 CFR 50.49 Environmental Qualification will be able to continue to perform their intended functions and that appropriate aging management will be performed during the subsequent period of extended operation.

2. A Condition Report was initiated to document an NRC violation due to failure to maintain required handholes dry. This failure resulted in the RHRSW cables in the program to be wetted. An Apparent Cause Evaluation was performed and resulted in a plant design change to add supports and straps to the handholes to lift the RHRSW pump cables above the expected high water level. Additionally, maintenance was performed on the sump pumps to improve the reliability. The combination of the repaired sump pumps and the plant modification, the cables have remained dry as documented in the continuing inspections of the handholes. No degradation of the cables due to the wetting was identified.

   This operating experience provides objective evidence that the Corrective Action Program, plant maintenance practices, and plant modifications are used to correct program deficiencies. This provides assurance that in-scope cables and connectors will be able to continue to perform their intended functions and that appropriate aging management will be performed during the subsequent period of extended operation.

3. On April 12, 2017, a Condition Report was created due to maintenance personnel finding damaged flex connections and motor damage to a supply fan. A work order was used to repair and replace the flex/conduit associated with the supply fan. Another work order was created and used to replace the motor and flexible conduit to the supply fan.

   Although this specific cable is not in-scope for this aging management program, this operating experience provides objective evidence that the Corrective Action Program, and plant maintenance practices will assure that in-scope cables and connectors will be able to continue to perform their intended functions, and that appropriate aging management will be performed during the subsequent period of extended operation.

4. On November 1, 2010, during an electrical license renewal inspection, degraded cables were found in the Reactor Building. A Condition Report was initiated to document the cable aging degradation and the cracking of the jacket. A work order was created to correct this aging degradation in the reactor building. A flex connection was determined to be degraded and was subsequently replaced.

   Although this specific cable is not in-scope for this aging management program, this operating experience provides objective evidence that the Corrective Action Program, and plant maintenance practices will assure that in-scope cables and connectors will be able to continue to perform their intended functions, and that appropriate aging management will be performed during the subsequent period of extended operation.

Conclusion

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 the identified aging effects will be adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.41 Metal Enclosed Bus

Program Description

The BFN Metal Enclosed Bus aging management program is an existing condition monitoring program and no actions are taken as part of this program to prevent or mitigate aging degradation. The program applies to metal enclosed buses within the scope of subsequent license renewal to identify age-related degradation of electrical insulating material (i.e., thermoplastic organic polymers), metallic, and elastomer components (e.g., gaskets, boots, and sealants). The program manages the effects of in-scope electrical bus portions of isolated and non-segregated phase bus associated with the Station Blackout path during the subsequent period of extended operation.

Metal Enclosed Bus internal surfaces are visually inspected for aging degradation including cracks, corrosion, foreign materials debris, excessive dust buildup, and evidence of moisture intrusion. Metal Enclosed Bus insulating material is visually inspected for signs of embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination. Internal bus insulating supports are visually inspected for structural integrity and signs of cracks. 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 or loss of strength. Both thermography and visual inspections are used at BFN to show that electrical insulating material, metallic, and elastomer components are free from the unacceptable aging effects. The first inspection for measuring connection resistance or thermography will be completed prior to the subsequent period of extended operation and every 10 years thereafter.

All unacceptable thermography and/or visual inspections will be documented in a corrective action and subject to an engineering evaluation. When the acceptance criteria are not met to demonstrate that the Metal Enclosed Bus intended function can be maintained consistent with the current licensing basis, an engineering evaluation(s) is performed to demonstrate that the inaccessible Metal Enclosed Bus segments, together with the accessible Metal Enclosed Bus inspection and test program, will continue to maintain the Metal Enclosed Bus consistent with the current licensing basis during the subsequent period of extended operation.

NUREG-2191 Consistency

The enhanced Metal Enclosed Bus aging management program will be consistent with the 10 elements of aging management program XI.E4, Metal Enclosed Bus, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Revise implementing procedures to add the following to the scope of the program:
    - Start Bus 1A and 1B.
    - Bus that connect the Unit Station Service Transformer 1A to the 4kV Common Board A
    - Bus between Start Bus 1A and 4kV Common Board A
    - Bus that connect the Unit Station Service Transformer 2A to the 4kV Common Board B
    - Bus between Start Bus 1B and 4kV Common Board B

   Program Element Affected: Element 1 – Scope of Program

2. Revise implementing procedures to require, for inaccessible Metal Enclosed Bus internal or external segments, documented engineering evaluation(s) to be performed to demonstrate that the inaccessible Metal Enclosed Bus segments evaluation, together with the accessible Metal Enclosed Bus inspection and test program, will continue to maintain the Metal Enclosed Bus consistent with the current licensing basis during the subsequent period of extended operation. These engineering evaluation(s) can be based on the results of accessible Metal Enclosed Bus inspections, tests, or other analyses.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected, Element 7- Corrective Actions

3. Revise implementing procedures to require 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 or loss of strength.

   Program Element Affected: Element 4 - Detection of Aging Effects

4. Revise implementing procedures to require documented visual inspection of insulation material to detect surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination, when thermography or measuring connection resistance of accessible bolted connections covered with heat shrink tape, sleeving, insulating boots, etc., is not possible, to validate the absence of surface anomalies,

such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination.

Program Elements Affected: Element 4 - Detection of Aging Effects, Element 6 - Acceptance Criteria

5. Revise implementing procedures to require, when an alternative visual inspection is used to check Metal Enclosed Bus bolted connections, that the first inspection be completed prior to the subsequent period of extended operation and every 5 years thereafter.

   Program Element Affected: Element 4 - Detection of Aging Effects

6. Revise implementing procedures to require trending of inspection results that are trendable and provide additional information on the rate of degradation when age related degradation is suspected or found.

   Program Element Affected: Element 5 - Monitoring and Trending

7. Revise implementing procedures to require all unacceptable thermography and/or visual inspections to be documented in a corrective action and subject to an engineering evaluation.

   Program Element Affected: Element 7 - Corrective Actions

8. Revise implementing procedures to require, when an unacceptable condition or situation that is identified, (e.g., internal surface degradation including cracks, corrosion, foreign debris, excessive dust buildup, moisture intrusion, insulating material embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination), a determination to be made as to whether the same condition or situation is applicable to Metal Enclosed Bus bolted connections not inspected or tested. Further, when acceptance criteria are not met, a determination will be made as to whether the surveillance, inspection, or test, including frequency intervals, needs to be modified.

   Program Element Affected: Element 7 - Corrective Actions

<u>Operating Experience</u>

The following examples of operating experience provide objective evidence that the Metal Enclosed Bus aging management program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for the Bus Inspection Program described in FSAR Section O.2.2. The Bus Inspection Aging Management Program is a plant specific program. The purpose of the program effectiveness review was to verify that the existing aging management program activities, to identify and correct, as warranted, age-related degradation of components monitored by the Inspections of the Bus Inspection Program, are being effectively implemented in the initial license renewal period of extended operation. The program effectiveness review was comprised of a review of inspection implementation activities to date and pertinent issues in the Corrective Action Program, searching for identified age-related degradation of components related to electrical Bus equipment. The program manages the effects of aging on the metal enclosed bus for in-scope electrical bus associated with the Station Blackout recovery. A review of the inspection results and issues in the Corrective Action Program during the initial period of extended operation determined that degradation was identified and documented, and conditions were evaluated. The review found that only minor degradation, such as cracking of Bus insulation was

identified. Age-related issues were evaluated and corrected under the Corrective Action Program resulting in effective implementation of this aging management program.

This operating experience provides objective evidence that the inspections, maintenance practices, and the Corrective Action Program effectively monitor the condition of the electrical Bus equipment to assure that electrical Bus equipment will be able to continue to perform their intended functions and that appropriate aging management program activities will be performed during the subsequent period of extended operation.

2. In 2020, inspections of Unit 1 bus were performed. During inspection of USST 1A and 1B insulation, cracks were identified on numerous locations on 4160 V non-segregated phase bus between USST 1A and 1B and their associated boards. The condition was entered in the Corrective Action Program and repairs were completed. In 2021, inspections of Unit 2 bus were performed. During inspection of USST 2A and 2B, it was determined that the wrong torque values were in the preventative maintenance work order. The issue was entered in the Corrective Action Program. The documentation was corrected, and all inspection were completed with acceptable results. In 2020, inspections of Unit 3 bus were performed. During inspection of USST 3A and 3B, cracks were found on insulation sleeves on the 5 kV Bus of the 3A 4 kV Unit Board breaker 1312. Also, during the inspection cracks and detached insulation sleeves were found on the 5 kV Bus of the 3B 4 kV Unit Board breaker 1314. These issues were entered in the Corrective Action Program and repairs were completed. In 2022, inspections of CSST A bus were performed, all inspection results were acceptable. In 2022, inspections of CSST B bus were performed, all inspection results were acceptable.

   This example provides objective evidence that the Bus Inspection aging management inspections are capable of detecting degradation to in-scope components and other indications of possible age-related degradation. This example also demonstrates that deficiencies are entered into the Corrective Action Program and actions are taken to evaluate and address deficiencies accordance with the Bus Inspection aging management program and the Corrective Action Program.

3. An Engineering Work Request (EWR), was initiated as a result of a corrective action to review the impact of NFPA 805, “Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants,” on License Renewal. The EWR identifies that when BFN adopted and transitioned to NFPA 805, the engineering processes did not identify that there were additional Buses with a License Renewal intended function. Corrective actions were developed to identify the additional Buses as the Normal and Alternate power to 4 kV Common Boards A and B, other actions to include the additional Buses into the testing and inspections performed by the Bus Inspection aging management program are being performed.

   This example of the use of the Corrective Action Program provides assurance that in-scope Bus equipment will be able to continue to perform their intended functions and that appropriate aging management will be performed during the subsequent period of extended operation.

4. There has been one self-assessment associated with the BFN License Renewal programs during the period of extended operation that reviewed the Bus Inspection program, conducted in 2022. This self-assessment evaluated the Bus Inspection Program and found no issues.

   This example provides objective evidence that periodic self-assessments of the Bus Inspection aging management program have been performed to identify and correct program elements that need improvement to maintain the quality performance of the program.

Conclusion

The enhanced Metal Enclosed Bus aging management program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.42 Fuse Holders

Program Description

The Fuse Holders aging management program is a new condition monitoring program. The program will apply to fuse holders outside of active devices susceptible to the following aging effects: increased resistance of connection due to chemical contamination, corrosion, and oxidation or fatigue caused by ohmic heating, thermal cycling, electrical transients, frequent removal and replacement, or vibration. It will also manage degradation of electrical insulation for the fuse holders with metallic clamps susceptible to the aging effects identified. Fuse holders inside an active device (e.g. switchgears, power supplies, inverters, battery chargers, and circuit boards) and not subject to the aging effects identified, are not within the scope of this program.

The metallic portion of fuse holders outside of active devices will be tested at least once every 10 years to assess the impact of any aging stressors. The specific type of test is determined prior to the initial test and detects increased resistance of fuse holder metallic clamp connections. Tests may include thermography, contact resistance testing, or other appropriately justified testing. The condition of the electrical insulation portion of the fuse holders outside of active devices will be visually inspected at least once every 10 years to provide an indication of the condition of the electrical insulation.

This new program will be implemented prior to the subsequent period of extended operation. The first sample inspections and tests will be completed prior to subsequent period of extended operation.

NUREG-2191 Consistency

The Fuse Holders aging management program will be consistent with the 10 elements of aging management program XI.E5, Fuse Holders, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Fuse Holders program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. On March 9, 2019, a condition report was entered into the Corrective Action Program due to a broken fuse block found during clearance placement activity. A work order was initiated and replaced the broken fuse block.

   This example provides objective evidence that Operations is using the plant procedures and processes to discover degraded conditions and correcting them with fuse holders.

2. On October 23, 2016, a condition report was entered into the Corrective Action Program due to a broken fuse clip found during clearance placement activity. A work order was initiated and replaced the broken fuse block.

   This example provides objective evidence that Operations is using the plant procedures and processes to discover degraded conditions and correcting them with fuse holders.

3. On November 6, 2019, a condition report was entered into the Corrective Action Program due to a loose fuse clip found during surveillance activity. During the performance of a surveillance, operators could not secure the Core Spray pump via a hand switch in the main control room. Operators had observed the red running light had extinguished immediately following the pump start, bulb was intact, and suspected trip circuit fuse issues. Electricians found a loose fuse clip in a 4kV Shutdown Board associated trip circuit. A work order was initiated and restored the loose fuse clip to proper working order.

   This example provides objective evidence that current maintenance practices are effective in identifying and correcting fuse holder deficiencies. This example also demonstrates that the appropriate guidance for evaluation, repair, or replacement is provided for locations where age-related degradation is found.

4. On October 14, 2014, a condition report was entered into the Corrective Action Program due to a hot spot on a fuse clip. While conducting a comparison survey by use of thermography of a panel in the auxiliary instrument room, a fuse terminal was running hotter than the other two terminals of a three fuse set. This led to an inspection of the same circuits on the other operating units; a similar fuse on one of the other units was also found to have a hot spot. A work order was initiated and resolved the issue.

   This example provides objective evidence that current maintenance practices are effective in identifying and correcting fuse holder deficiencies. This example also demonstrates that age related degradation issues are entered into the Corrective Action Program and appropriate corrective actions are taken to evaluate and correct the deficiencies.

Conclusion

The Fuse Holders aging management program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.2.1.43 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 aging management program is a new condition monitoring program. Cable connections associated with cables within the scope of subsequent license renewal that are external connections terminating at active or passive devices, are in the scope of this program.

Wiring connections internal to an active assembly are considered part of the active assembly and, therefore, are not within the scope of this program.

This program will implement one-time testing of the metallic parts of a representative sampling of cable connections within the scope of subsequent license renewal. The sample of cable connections within the scope of license renewal will be tested on a one-time test basis or periodically once every 5 years, if only visual inspection is used during the one-time test 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 10 years of initial testing. One-time testing will provide an indication of increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation. Representative samples of each type of electrical cable connection will be tested. The following factors will be considered for sampling: voltage level (medium and low-voltage), circuit loading (high load), connection type, and location (high temperature, high humidity, vibration, etc.). The technical basis for the sample selection will be documented.

Testing may include thermography, contact resistance testing, or other appropriate testing methods without removing the connection insulation. One-time testing provides additional confirmation to support industry OE that shows that electrical connections have not experienced a high degree of failures, and that existing installation and maintenance practices are effective. This one-time testing will also confirm that there are no aging effects requiring management during the subsequent period of extended operation. Twenty percent of a connector type population with a maximum sample of 25 constitutes a representative connector sample size.

The acceptance criteria will be specific for each type of test and the specific type of cable connections tested. Cable connections should not indicate abnormal temperatures when measured by thermography. Connections which cannot be adequately assessed by thermography will be assessed by contact resistance measurement or another appropriate test. When the visual inspection alternative for covered cable connections is used, the absence of embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination indicates that the covered cable connection components are not loose. Results that do not meet the acceptance criteria will be addressed in the Corrective Action Program. The findings of the initial one-time test will also be evaluated to determine whether periodic testing of the cable connections is warranted. The justification and technical basis for not performing subsequent periodic testing will be documented.

This new program will be implemented prior to the subsequent period of extended operation. The first sample inspections and tests will be completed prior to subsequent period of extended operation.

NUREG-2191 Consistency

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements aging management program will be consistent with the 10 elements of aging management program XI.E6, Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. A Condition Report was initiated to document that during field work Maintenance Electricians were collecting amperage readings for an air handling unit. During the performance of the task it was suspected the field side motor connections were possibly loose in the breaker compartment access trough. All amperage and voltage readings were acceptable and satisfactory. Thermography was performed and “C” phase showed 30 degrees F higher than other phases which were at 158 degrees F. BFN Engineering and Predictive Maintenance groups were contacted and based on the thermography values, it was determined that repair should occur during the next scheduled system work week. A work order was completed to resolve the issue and found that motor leads were loose. Motor leads were tightened.

   This operating experience provides objective evidence that the Corrective Action Program, plant maintenance practices, and plant engineering are used to document, evaluate, and correct potential electrical connection issues. This provides assurance that in-scope Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification will be able to continue to perform their intended functions and that appropriate aging management will be performed during the subsequent period of extended operation.

2. A Condition Report was initiated to document that during Unit 1 testing for Source Range Monitors, it was identified that the inboard (reactor side) penetration connection for Source Range Monitor 1C was significantly degraded and should be repaired / replaced at the next maintenance opportunity. A reactivity management review was performed that determined this condition to have no impact on reactivity management. A work order was completed to repair and retest the connection to restore the electrical continuity of this penetration connection.

   This operating experience provides objective evidence that the Corrective Action Program, plant maintenance practices, and plant engineering are used to document, evaluate, and correct potential electrical penetration connection issues. This provides assurance that in-scope Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification will be able to continue to perform their intended functions and that appropriate aging management will be performed during the subsequent period of extended operation.

3. A Condition Report was initiated to document that during thermography testing the 250V Main Battery Charger number 4 had a hot spot. Specifically, the AC input breaker for this battery charger had a hot “B” phase wire (in the top of the breaker). The “B” phase wire was 24 degrees F hotter than the “C” phase wire (the “B” phase wire was 154 degrees F and the “C” phase wire was 130 degrees F). A Condition Report was written to document the issue and to review the level of degradation. Based on the nature of the problem, BFN Predictive Maintenance group personnel did not consider this condition to affect the qualification nor did this condition affect the current functional capabilities of the component. A work order was completed to repair the connection to restore electrical continuity.

   This operating experience provides objective evidence that the Corrective Action Program, plant maintenance practices, and plant engineering are used to document, evaluate, and correct potential electrical connection issues. This provides assurance that in-scope Electrical

Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification will be able to continue to perform their intended functions and that appropriate aging management will be performed during the subsequent period of extended operation.

4. A Condition Report was written to document a condition from the Sequoyah Nuclear Plant and evaluate the BFN program to identify any areas for improvement based upon this external operating experience. A TVA Fleet Loose Connections Action Plan was issued based on multiple instances of loose electrical connections/wiring issues leading to plant transients, including a Sequoyah Nuclear Plant Unit 1 manual scram due to a loose connection on the Main Steam Isolation Valve Hand Switch in the Main Control Room. As a result of this operating experience, a Condition Report and two Work Orders were initiated at BFN and completed to address the applicable aspects of this issue. These two Work Orders each required inspection of multiple electrical panels and resulted in the identification and correction of several potentially loose connections.

   This operating experience provides objective evidence that operating experience from other TVA sites is used to identify improvement opportunities, and that the Corrective Action Program is used to develop and implement corrective actions, to assure that in-scope Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification will be able to continue to perform their intended functions and that appropriate aging management will be performed during the subsequent period of extended operation.

Conclusion

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.3.0 NUREG-2191 Chapter X Aging Management Programs

This section provides summaries of the NUREG-2191 Chapter X programs credited for managing the effects of aging.

B.3.1.1 Fatigue Monitoring

Program Description

The Fatigue Monitoring aging management program is an existing program that manages fatigue damage of reactor vessel components, reactor coolant pressure boundary piping components, and other components. The program monitors and tracks the number of critical thermal, pressure, and seismic transients to ensure that the cumulative usage factor (CUF) and environmentally-assisted fatigue (CUF_{en}) for each analyzed component does not exceed the applicable limit through the subsequent period of extended operation. The program monitors and tracks the number and severity of thermal and pressure transients for BFN as specified In FSAR Section 4.2.5, which is referenced in Technical Specifications Section 5.5.5, Component Cyclic and Transient Limits. No BFN ANSI B31.1 and ASME Code Class 2 and 3 maximum allowable stress range reduction/expansion stress analyses have been dispositioned in accordance with 10 CFR 54.21(c)(1)(iii), therefore this program does not apply to these analyses. No ASME Section III fatigue waiver analyses have been dispositioned in accordance with 10 CFR 54.21(c)(1)(iii), therefore this program does not apply to fatigue waiver analyses. No cycle-based flaw growth, flaw tolerance, or fracture mechanics analyses that are based on cycle-based loading assumptions have been dispositioned in accordance with 10 CFR 54.21(c)(1)(iii), therefore this program does not apply to flaw growth; flaw tolerance, or fracture mechanics analyses. The program also monitors applicable design transient parameters (e.g., temperatures, pressures, displacements, strains, flow rates, etc.) for components with stress-based fatigue calculations.

The program utilizes the FatiguePro™ software which is a computerized data acquisition, recording, and tracking program. FatiguePro™ is used to determine the overall cumulative number of transient cycles that have occurred at a given time and determines the CUF values resulting from the combination of transient cycles that have occurred. The program monitors the environmental effects of reactor coolant on Class 1 components by using the guidance in Regulatory Guide 1.207, Revision 1, applicable fatigue curves in NUREG/CR-6909, Revision 1, and calculated alternating stress values from the existing ASME Code fatigue calculations to determine CUF_{en} values. FatiguePro™ performs “stress-based” and “cycle-based” fatigue monitoring.

The cumulative CUF and CUF_{en} values for the components monitored by FatiguePro™ are compared to appropriate allowable limits (e.g., 1.0 for ASME Section III locations, or 1.0 for CUF_{en} for environmental fatigue locations). When a cumulative CUF or CUF_{en} value exceeds 70 percent of applicable allowable limit, corrective action is taken to review the applicable fatigue analyses and take appropriate actions to prevent exceeding the limit.

This program verifies the continued acceptability of existing fatigue analyses through transient cycle counting and calculation of cumulative CUF and CUF_{en} values to demonstrate that they continue to meet the appropriate limits. The program requires comparison of actual event parameters to the applicable design transient definitions to ensure the actual transient is bounded by the applicable design transient. CUF and CUF_{en} values are computed parameters used to assess the likelihood of fatigue damage. Fatigue crack initiation is assumed to begin in a mechanical or structural component when the CUF and CUF_{en} values reach the value of 1.0.

<u>NUREG-2191 Consistency</u>

The enhanced Fatigue Monitoring aging management program will be consistent with the 10 elements of aging management program X.M1, Fatigue Monitoring, specified in NUREG-2191.

<u>Exceptions to NUREG-2191</u>

None.

<u>Enhancements</u>

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Revise implementing procedures to require monitoring of the Refueling Containment Skirt within the scope of the program.

   Program Element Affected: Element 1 - Scope of Program

2. Revise implementing procedures to require component locations that are in the scope of the program to be revised based on operating experience, plant modifications, and inspection findings.

   Program Element Affected: Element 1 - Scope of Program

3. Revise implementing procedures to ensure periodic review of chemistry parameters that give inputs to F_{en} factors used in CUF_{en} calculations for environmentally-assisted fatigue calculations.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

4. Analysis has been completed to re-evaluate the cumulative fatigue limit for the recirculation inlet nozzle safe ends, and the limits will be revised in FatiguePro™ prior to entry into the subsequent period of extended operation.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

5. FatiguePro™, Version 4, will be implemented prior to entry into the subsequent period of extended operation.

   Program Element Affected: Element 3 - Parameters Monitored or Inspected

6. Revise implementing procedures to provide for modifications to fatigue analyses or other corrective actions on an "as-needed" basis if assumed parameter values are approached, if transient severities exceed the design or assumed severities, if transient counts exceed the design or assumed quantities, if the definition of a transient is modified, if new transient events are identified, or if plant modifications to components change specified geometries.

   Program Element Affected: Element 5 - Monitoring and Trending

7. Revise implementing procedures to reflect the re-evaluated cumulative fatigue values for the Units 1, 2, and 3 recirculation inlet nozzle safe ends.

   Program Element Affected: Element 6 - Acceptance Criteria

8. Revise implementing procedures to require corrective actions for any locations projected to exceed a CUF or CUF_{en} of 1.0 during the subsequent period of extended operation, to include:
   - Repair or replacement of the component or
   - Provide a more rigorous analysis of the component to demonstrate that the CUF or CUF_{en} will not exceed 1.0 during the subsequent period of extended operation or
   - Perform a flaw tolerance analysis with appropriate (e.g., inclusion of environmental effects) crack growth rate curves and associated inspections performed in accordance with Appendix L of ASME Code Section XI.

   Program Element Affected: Element 7 - Corrective Actions

9. Revise implementing procedures for CUF_{en} analyses projected to exceed a 1.0 during the subsequent period of extended operation, that scope expansion will included consideration of other locations with the highest expected CUF_{en} values.

   Program Element Affected: Element 7 -Corrective Actions

<u>Operating Experience</u>

The following examples of operating experience provide objective evidence that the Fatigue Monitoring Program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for the Fatigue Monitoring program described in FSAR Section O.1.36 in support of preparing the BFN Subsequent License Renewal Application. The purpose of the program effectiveness review was to verify that the management of metal fatigue of select components in the reactor coolant pressure boundary and primary containment are being effectively implemented in the initial license renewal period of extended operation. This aging management program for BFN Units 1, 2 and 3 monitors and tracks the number of critical thermal and pressure transients for selected components. This program ensures that BFN does not exceed the design limit on fatigue usage of the selected components during the period of extended operations. The Fatigue Monitoring program uses the EPRI FatiguePro™ Fatigue Monitoring software, Version 3.0, to monitor fatigue on the reactor vessel components. This software has been in use for the entirety of the period of extended operation. Annual reports are generated to assess the cumulative fatigue against the established limits. The program effectiveness review was comprised of a review of the annual reports, and any conditions entered into the Corrective Action Program. The review of the current yearly report indicates that all values are below their respective limit, and not expected to exceed the limit during the period of extended operation. There are three fatigue points that are below the fatigue limit but require re-evaluation prior to entry into the subsequent period of extended operation. All three unit's reactor recirculation inlet nozzle safe ends are above the trigger values of 70%. These points will continue above the trigger value throughout the period of extended operation, until the limits are re-evaluated. The rate of rise is documented in the Corrective Action Program and are monitored and trended each year. The rate of rise supports remaining below the limit for the duration of the period of extended operation. Analysis has been completed to re-evaluate the cumulative fatigue limit for the recirculation inlet nozzle safe ends, and the limits will be revised in FatiguePro™ prior to entry into the subsequent period of extended operation. These revisions in the fatigue model will coincide with implementation of FatiguePro™, Version 4, prior to entry into the subsequent period of extended operation.

   This operating experience provides objective evidence that cumulative fatigue is being effectively monitored and trended in accordance with the Fatigue Monitoring program during the period of extended operation. Continued implementation of the Fatigue Monitoring program will ensure that the monitored components will continue to perform their intended functions during the subsequent period of extended operation.

2. The 2018 Fatigue Monitoring report had the Unit 2 reactor vessel support skirt at 90% of the limit and the Unit 3 reactor vessel support skirt at 85%. A General Electric Hitachi Task Report was completed in June 2015 for the Extended Power Uprate (EPU) project. For the support skirts on all three units, a finite element analysis was performed to remove conservatism in Cumulative Usage Factor (CUF) evaluations. This resulted in the pre-EPU CUF for the support skirts being reduced from 0.904 to a 60-year post-EPU CUF of 0.129.

   This operating experience provided objective evidence that cumulative fatigue is evaluated and analyzed to ensure that failure of intended functions due to fatigue are prevented. Continued implementation of the Fatigue Monitoring Program will ensure that cumulative fatigue will be effectively evaluated during the subsequent period of extended operation.

3. Three QA audits were conducted during the period of extended operation which evaluated the Fatigue Management program. In the audits, three deficiencies and five recommendations was documented. One deficiency was associated with issues in evaluating and reporting conditions where the fatigue trigger value of 70% was exceeded. This deficiency was entered into the Corrective Action Program and was corrected by a revision to the implementing procedure. The other deficiencies were administrative in nature. All these deficiencies and

recommendations were entered into the Corrective Action Program. Corrective actions developed to address the conditions have been completed.

This operating experience provides objective evidence that program audits and the Corrective Action Program are used to ensure that cumulative fatigue is being effectively monitored and trended during the period of extended operation. Continued implementation of the Fatigue Monitoring Program will ensure that cumulative fatigue will be effectively monitored and trended during the subsequent period of extended operation.

Conclusion

The enhanced Fatigue Monitoring program will provide reasonable assurance the cumulative fatigue of in-scope components have been effectively monitored and trended, and that continued implementation of the Fatigue Monitoring program will assure that this fatigue will be effectively monitored and trended during the subsequent period of extended operation.

B.3.1.2 Neutron Fluence Monitoring

Program Description

The Neutron Fluence Monitoring aging management program is a new condition monitoring program that monitors and tracks increasing neutron fluence (integrated, time-dependent neutron flux exposures) to reactor vessel and reactor vessel internal (RVI) components to ensure that applicable reactor vessel neutron embrittlement analyses (i.e., TLAAs) and radiation-induced aging effect assessments for reactor internal components will remain within their applicable limits. The program manages loss of fracture toughness due to neutron irradiation embrittlement. The components evaluated by these analyses are the reactor vessel shell, welds and nozzles in the extended beltline region and RVI components subject to reactor coolant and neutron flux environment which are fabricated from carbon or low alloy steel with stainless steel cladding, stainless steel, and nickel alloy materials.

The 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 to verify the adequacy of neutron fluence projections, which are defined for the CLB in NRC approved reports. For fluence monitoring activities that apply to the extended beltline region of the reactor vessel(s), the calculational methods are performed in a manner that is consistent with NRC Regulatory Guide 1.190, Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence, March 2001. The methods used to identify materials within the extended beltline region and RVI components are also consistent with NRC-approved methodology in Regulatory Guide 1.190.

The methods and assumptions for determining reactor vessel neutron fluence for the extended beltline region are consistent Regulatory Guide 1.190. The methods and assumptions used for the beltline region are considered appropriate for the beltline region that has been extended to encompass materials projected to experience fluence in excess of 1×10^{17} n/cm^2 (E > 1 MeV) at the end of the subsequent period of extended operation, since the extended region does not extend significantly above or below the active fuel region and no additional reactor vessel plate materials (heat numbers) or welds are projected to experience fluence exceeding 1×10^{17} n/cm^2

(E > 1 MeV). The NRC Regulatory Guide 1.190 compliant TransWare Enterprises Radiation Analysis Modeling Application (RAMA) fluence methodology, which was approved by the NRC for reactor vessels and specific RVI components, utilizes representative BWR surveillance capsule measurements to validate calculational fluence analysis.

The determination of RVI component fast neutron fluence values is not governed by specific regulatory guidance or requirements. The purpose of determining the fast neutron fluence values of RVI components is to identify applicable degradation mechanisms (e.g., irradiated assisted stress corrosion cracking, neutron embrittlement, etc.), crack growth rates, and support for weldability determinations. The method used to determine the RVI component neutron fluence values was the RAMA fluence methodology which was approved by the NRC for specific RVI components. Although the NRC approval was for specific components (core shroud and top guide), the methodology is appropriate for other components since the methodology has been utilized throughout the industry for RVI component fluence determinations. The calculated component fluence is compared to conservative criteria to determine if a threshold value was crossed to identify applicable degradation mechanisms (e.g., irradiated assisted stress corrosion cracking, neutron embrittlement, etc.), to determine crack growth rates, and support weldability determinations. Ongoing inspections of the RVI components for age-related degradation due to neutron irradiation are also performed in accordance with the BWR Vessel Internals program (B.2.1.7). The Neutron Fluence program results are compared to the neutron fluence parameter inputs used in the neutron embrittlement analyses for reactor vessel components. This includes but is not limited to the neutron fluence inputs for the reactor vessel upper-shelf energy analyses (or equivalent margin analyses, as applicable to the CLB) and pressure-temperature limits analyses that are required to be performed in accordance in 10 CFR Part 50, Appendix G requirements. Comparisons to the neutron fluence inputs for other analyses (as applicable to the CLB) include those for mean RT_{NDT} and probability of failure analyses for BWR reactor vessel circumferential and axial shell welds, BWR core reflood design analyses, and aging effect assessments for BWR reactor internals that are induced by neutron irradiation exposure mechanisms. Plant issues or conditions resulting in non-compliance with the requirements of 10 CFR Part 50, Appendix G or 10 CFR Part 50, Appendix H are entered into the Corrective Action Program. If the neutron fluence assumptions in reactor vessel analyses or augmented inspection bases for RVI components are projected to be exceeded, corrective actions can include updating the analyses for the reactor vessel components or assessing the need to revise the augmented inspection bases for RVI components.

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 (B.2.1.19) provide inputs to and have impacts on the neutron fluence monitoring results that are tracked by this program. In addition, regulatory requirements in the plant Technical Specifications or in specific regulations of 10 CFR Part 50 may apply, including those in 10 CFR Part 50, Appendix G and 10 CFR 50.55a.

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

<u>NUREG-2191 Consistency</u>

The Neutron Fluence Monitoring aging management program will be consistent with the 10 elements of aging management program X.M2, Neutron Fluence Monitoring, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

None.

Operating Experience

The following examples of operating experience provide objective evidence that the Neutron Fluence Monitoring aging management program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In support of the Neutron Fluence Monitoring program (as part of the Reactor Vessel Material Surveillance program), capsules have been withdrawn from the BFN Unit 2 reactor vessel, and tested in accordance with 10 CFR Part 50, Appendix H. Two BFN Unit 2 test specimen surveillance capsules have previously been withdrawn and tested as part of the original plant-specific capsule removal and testing schedule and the BWRVIP Integrated Surveillance Program (ISP). During the Unit 2 Refueling Outage (U2R7) in 1994, the surveillance capsule at 30° azimuth was removed for testing. The capsule was reinstalled in the reactor vessel with reconstituted specimens during Unit 2 Refueling Outage 8 (U2R8) in 1996. The ISP, which was initiated in 1999, was designed to replace the original plant-specific surveillance capsule programs with representative capsules in host BWR plants. BFN committed to use the ISP in place of its existing surveillance programs, and implementation was approved by the NRC for BFN Unit 1 in License Amendment 273, for BFN Unit 2 in License Amendment 279, and for BFN Unit 3 in License Amendment 238. BFN Unit 2 was designated as a host plant and has withdrawn and tested the capsule at 120° azimuth in Unit 2 Refueling Outage 16 (U2R16) in 2011. The results of this surveillance specimen evaluation were used in the establishment of the current Technical Specification Pressure-Temperature Limit curves documented in NEDC-33445P, R0, for Unit 1, NEDC-33854P, R0 for Unit 2, and NEDC-33857P, R0 for Unit 3. An additional BFN Unit 2 test specimen surveillance capsule is scheduled for withdrawal during the License Renewal period of extended operation. This capsule is the third set of Unit 2 test specimens, located at azimuth 300°, which is currently scheduled for removal in the refueling outage closest to, but without exceeding, 40 EFPY of operation. At the present time, this would correspond to Unit 2 Refueling Outage 25 (U2R25) in 2029.

   This operating experience provides objective evidence that participation in the ISP in accordance with the existing Reactor Vessel Material Surveillance program (B.2.1.19) will be used to effectively monitor the loss of fracture toughness of the reactor vessel extended beltline materials due to neutron irradiation embrittlement, and there is confidence that implementation of the new Neutron Fluence Monitoring program will effectively manage the effects of aging, and initiate corrective actions prior to loss of intended function during the subsequent period of extended operation.

2. Fluence was calculated for the BFN reactor vessel for the extended 60-year (38 EFPY for Unit 1, 48 EFPY for Unit 2, 54 EFPY for Unit 3) licensed operating period, using the methodology of NEDC-32983P-A, Revision 2, “General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation,” which was approved by the NRC in a letter dated November 17, 2005 from Herbert N. Berkow (NRC) to George B. Stramback (GE). Peak fluence was calculated at the reactor vessel inner surface (inner diameter), for purposes of evaluating upper-shelf energy (USE). The value of neutron fluence was also calculated for

the 1/4T location into the reactor vessel wall measured radially from the ID, using Equation 3 from Paragraph 1.1 of NRC Regulatory Guide 1.99, Revision 2. This 1/4T depth is recommended in the ASME Boiler and Pressure Vessel Code Section XI, Appendix G, Subarticle G-2120, as the maximum postulated defect depth.

This operating experience provides objective evidence that the analyses that use neutron fluence as an input are reviewed and updated, which provides reasonable assurance that the implementation of the new Neutron Fluence Monitoring aging management program will effectively manage aging by identifying degradation prior to failure or loss of intended function during the subsequent period of extended operation.

3. Since 2019, BFN has implemented an Extended Power Uprate (EPU) from a licensed thermal power of 3458 megawatts thermal (MWt) to 3952 MWt on all three units, and has also subsequently implemented the Maximum Extended Load Line Limit Analysis Plus (MELLLA+) operating strategy. The changes in core neutron fluence associated with these plant licensing modifications resulted in reanalysis of the associated fluence projections and associated reactor vessel irradiation embrittlement analyses. The revised neutron fluence projections were utilized as inputs in the current licensing basis reactor vessel neutron irradiation embrittlement analyses for Unit 1, Unit 2 and Unit 3 beltline components, including analyses of USE, adjusted reference temperatures (ART), pressure-temperature (P-T) limits, axial and circumferential weld failure probability, and reactor vessel and core shroud reflood thermal shock utilizing GE Discrete Ordinates Transfer (DORT) fluence methodology. These revised neutron fluence exposures were also used as input in analyses of BFN Units 1, 2, and 3 reactor vessel internals components, including the core shroud, top guide, core plate and core plate bolts, and jet pumps (and jet pump repair hardware).

   This operating experience provides objective evidence that the analyses that use neutron fluence as an input are reviewed and updated, as required, which provides reasonable assurance that the implementation of the new Neutron Fluence Monitoring aging management program will effectively manage aging by identifying degradation prior to failure or loss of intended function during the subsequent period of extended operation.

Conclusion

The Neutron Fluence Monitoring program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

B.3.1.3 Environmental Qualification of Electric Equipment

Program Description

The Environmental Qualification of Electric Equipment aging management program is an existing preventive program that manages the aging of electrical equipment within the scope of 10 CFR 50.49, “Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants.” The program includes electric equipment composed of various polymeric and metallic materials that is important to safety. The scope of equipment included in the Environmental Qualification (EQ) Program is identified in the BFN 10 CFR 50.49 List. The BFN EQ Program is governed by a TVA procedure, which controls the EQ Program, defines responsibilities, and specifies requirements to establish and maintain auditable documentation demonstrating qualification of equipment in compliance with 10 CFR 50.49 and the license renewal aging management provisions of 10 CFR Part 54. The purpose of the BFN EQ Program is to “verify that all plant equipment covered under 10 CFR 50.49 is qualified for its application and meets its specified performance requirements when subjected to the conditions predicted to be present when it must perform its safety function up to the end of its qualified life.” This includes demonstrating that EQ program electrical equipment located in adverse localized environments or harsh plant environments, that is, those areas of the plant that could be subject to the harsh environmental effects of a loss of coolant accident (LOCA), high energy line break and post-LOCA environment, are qualified to perform their safety function in those harsh environments after the effects of in-service (operational) aging.

10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of EQ. To meet this requirement, the program performs TLAAs that establish the equipment service condition tolerance and aging limits (e.g., qualified life or condition limit). These analyses provide justification for life extension of the BFN EQ equipment from 60 years to 80 years. Methods used comply with industry practices such as NUREG 0588, IEEE 323, etc. for environmental qualification of 10 CFR 50.49 equipment in a harsh environment using results from type testing, material analysis, or analysis in combination with testing.

The aging effects of electrical components subject to the requirements of 10 CFR 50.49 are managed in the EQ Program in accordance with the requirements of 10 CFR 54.21(c)(1)(iii). The qualified life of EQ components at BFN is not based on condition or performance monitoring. Qualification of components for the extended license renewal term is established in the same way the equipment was originally qualified and is documented in the applicable calculations. These and other EQ analyses provide and document reasonable assurance that electric equipment important to safety, for which a qualified life has been established, can perform its safety function(s) without experiencing common cause failures before, during or after applicable design basis events.

Equipment located in a mild environment (an environment that at no time would be significantly more severe than the environment occurring during normal operation, including anticipated operational occurrences as defined in 10 CFR 50.49) is not part of an EQ program per 10 CFR 50.49(c). Demonstration that this non-EQ equipment meets its functional requirements during normal environmental conditions and anticipated operational occurrences is provided by BFN design and licensing basis. Documents that demonstrate that a non-environmentally qualified component is qualified or designed for a mild environment include design/purchase specifications, seismic test qualification reports, evaluations, or certifications of conformance.

The program complies with 10 CFR 50.49(e) which states that electric equipment qualification programs must include and be based on temperature, pressure, humidity, chemical effects, radiation, aging, submergence, and consideration of synergistic effects. Additionally, the program complies with the requirements of 10 CFR 50.49(e) regarding the application of margins to account for unquantified uncertainties, including production variations, and inaccuracies in test instruments. These margins are in addition to any conservatism applied during the derivation of local environmental conditions of the equipment unless these conservatisms are quantified and shown to contain the appropriate margins.

The BFN approach for EQ is consistent with industry practices for environmental qualification of 10 CFR 50.49 equipment in a harsh environment using results from type testing, material analysis, or analysis in combination with testing.

The program implements the requirements of 10 CFR 50.49 and provides reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

Activities to visually inspect accessible, passive EQ equipment located in adverse localized environments at least once every 10 years will be added to the program prior to the subsequent period of extended operation.

If an EQ component is found to be outside the bounds of its qualification basis or when an unexpected adverse localized environment or condition is identified during operational or maintenance activities, the qualification of the affected EQ equipment is evaluated in the Corrective Action Program. Corrective actions are taken to resolve the condition.

NUREG-2191 Consistency

The enhanced Environmental Qualification of Electric Equipment aging management program will be consistent with the 10 elements of aging management program X.E1, Environmental Qualification of Electric Equipment, specified in NUREG-2191.

Exceptions to NUREG-2191

None.

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements.

1. Revise implementing procedures to add activities to visually inspect accessible, passive EQ equipment located in adverse localized environments at least once every 10 years. The first periodic visual inspection will be performed prior to the subsequent period of extended operation.

   Program Element Affected: Element 4 - Detection of Aging Effects

2. Revise implementing procedures to establish acceptance criteria for the visual inspections of accessible, passive EQ equipment located in adverse localized environments.

   Program Element Affected: Element 6 - Acceptance Criteria

Operating Experience

The following examples of operating experience provide objective evidence that the Environmental Qualification of Electric Equipment aging management program will be effective in assuring that intended functions are maintained consistent with the current licensing basis for the subsequent period of extended operation.

1. In 2022, a program effectiveness review was performed for the Environmental Qualification Program described in FSAR Section O.1.35 in support of preparing the BFN Subsequent License Renewal Application. The purpose of the program effectiveness review was to verify that the management of certain electrical components that are important to safety and could be exposed to harsh environment accident conditions, as defined in 10 CFR 50.49 are being effectively implemented in the initial license renewal period of extended operation. The Environmental Qualification Program is an existing program that was established to meet 10 CFR 50.49 requirements. It is consistent with NUREG-1801 Section X.E1, “Environmental Qualification (EQ) of Electric Components.” The program effectiveness review was comprised of a review of EQ inspection reports in maintenance documentation, any conditions entered

into the Corrective Action Program, and review of Quality Assurance program audits. A sample of Work Orders (WO) containing EQ inspections were reviewed. These WOs indicate that the EQ inspections are being performed as required, and with the correct level of detail. Specific items to be inspected, along with specific actions to take, were included in the EQ Maintenance Work Record.

This operating experience provides objective evidence that inspection and testing activities taken as part of the Environmental Qualification Program along with the Corrective Action Program will assure that in-scope components in the EQ program will be able to continue to perform their intended functions, and that appropriate aging management will be performed during the subsequent period of extended operation.

2. During the 2022 program effectiveness review, it was identified that EQ degradation inspections and adverse degradation trends are not required by procedure to be documented in the Corrective Action Program. Alternate documentation is procedurally allowed by the EQ program governing procedure. The EQ degradation inspections and adverse degradation trends are reviewed and maintained by the EQ Program engineer. Failure to document EQ issues in the Corrective Action Program could challenge the tracking and trending of EQ issues, and potentially prevent the operability assessment by Operations for degradation trend. This condition was entered into the Corrective Action Program and actions were developed to revise the EQ program governing procedures to require documentation of degraded EQ conditions into the Corrective Action Program.

   This operating experience provides objective evidence that Environmental Qualification Program self-assessments are used to identify deficient conditions in the program, and for the Corrective Action program to correct those conditions. This provides assurance that the Environmental Qualification Program will be maintained to protect intended functions during the subsequent period of extended operation.

3. Audits are routinely performed by QA on the EQ program. Although performance deficiencies were identified during these audits, none were related to any aspect of aging management. One gap identified by QA during a 2018 audit is the failure to provide timely updates to the program EQ binders. Revisions were identified that were over one year old at the time of the audit, which is outside the procedural requirements of 30 working days. This deficiency was entered into the Corrective Action Program, and corrective actions were developed and completed. An additional gap identified by QA in an audit conducted in 2020 was a delay in replacing non-conforming electrical leads to solenoid valves. In 2017, it was identified that six valves were installed in the nitrogen system (outside the drywell) with test leads in place of the evaluated leads. The test leads are rated for 150 degrees C, not the 200 degrees C as required. The valves remained functional based on the evaluation that the leads are in a mild environment and are not exposed to high temperatures, even under accident conditions. This issue was entered into the Corrective Action Program. To date, four of the six leads have been replaced, with the remaining two scheduled for replacement.

   This operating experience provides objective evidence that evaluations and assessments are used in the Environmental Qualification Program to identify deficient conditions in the program, and for the Corrective Action program to correct those conditions. This provides assurance that the Environmental Qualification Program will be maintained to protect intended functions during the subsequent period of extended operation.

4. NRC Information Notice 2015-12, “Unaccounted for Error Terms Associated with the Irradiation Testing and Environmental Qualification of Important-To-Safety Components,” was issued on November 20, 2015. This Information Notice details the failure of a specialized irradiation testing facility to properly control the applied radiation dose to components being

tested for Environmental Qualification. This Information Notice referenced IEEE Standard 323-1974, which states that a margin of 10 percent of the accident dose should be used during the qualification process to account for uncertainties associated with variations in commercial production, inaccuracies in test equipment, and reasonable errors in defining satisfactory performance. BFN personnel entered this Information Notice into the Corrective Action Program for evaluation. An IEEE Guidance Position Paper was utilized to perform screenings of all active EQ binders to determine impact to EQ devices addressed by the binders. As a result of the screenings, it was revealed that the subject testing facility provided irradiation services for 67 of the BFN EQ binders. It was then determined that for 64 of those binders, sufficient margin exists in the test exposure dose to allow subtraction of 10 percent for errors and still have all devices addressed by those 64 binders remain qualified (tested) for radiation doses greater than the plant requirements. Where 10 percent or greater margin in test exposure dose did not exist in three EQ binders, the plant required dose versus the test exposure dose has been addressed and documented in those three binders and were verified to be acceptable.

This operating experience provides objective evidence that industry operating experience is used in the Environmental Qualification Program to identify potentially deficient conditions in EQ components and the EQ program, and for the Corrective Action Program to address those conditions. This provides assurance that the Environmental Qualification program will be maintained to protect intended functions during the subsequent period of extended operation.

Conclusion

The enhanced Environmental Qualification of Electric Equipment program will provide reasonable assurance that the identified aging effects will be adequately managed so that the intended functions of components within the scope of subsequent license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.

Appendix C - Response to BWRVIP License Renewal Applicant Action Items

Of the BWRVIP reports credited within BFN Subsequent License Renewal aging management programs, the following include NRC Safety Evaluation Reports (SERs) that include action items applicable to license renewal applicants:

- BWRVIP-18-R2-A; BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines
- BWRVIP-25-R1-A; BWR Core Plate Inspection and Flaw Evaluation Guidelines
- BWRVIP-26-A; BWR Top Guide Inspection and Flaw Evaluation Guidelines
- BWRVIP-27-A; BWR Standby Liquid Control System/Core Plate dP Inspection and Flaw Evaluation Guidelines (Credited in BWR Penetrations program)
- BWRVIP-38; BWR Shroud Support Inspection and Flaw Evaluation Guidelines
- BWRVIP-41-R4-A; BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines
- BWRVIP-42-R1-A, BWR LPCI Coupling Inspection and Flaw Evaluation Guidelines
- BWRVIP-47-A, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines (Credited in BWR Penetrations program)
- BWRVIP-48 R2, BWR Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines (Credited in BWR Vessel ID Attachment Weld program)
- BWRVIP-49-A, BWR Instrument Penetration Inspection and Flaw Evaluation Guidelines (Credited in BWR Penetrations program)
- BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guideline for License Renewal
- BWRVIP-76-R1-A, BWR Core Shroud Inspection and Flaw Evaluation Guidelines
- BWRVIP-139-R1-A, Steam Dryer Inspection and Flaw Evaluation Guidelines

License renewal applicant action items identified in the corresponding SERs for each of the above BWRVIP reports are addressed in the following tables. BWRVIP reports without SERs for license renewal do not have action items and are therefore not included in the tables.

It is recognized that the first three action items from each of the license renewal SERs applicable to the above BWRVIP reports are fundamentally identical, with the exception of BWRVIP-139-R1-A. For that reason, they are combined in the table and addressed together.

Additionally, the draft NRC SER for BWRVIP-315 includes two License Conditions and four Applicant Action Items regarding the applicability of the BWRVIP-315 guidance during the subsequent period of extended operation. For the purposes of this SLRA, these items are addressed following the table associated with BWRVIP-139-R1-A, in advance of the final issuance of the NRC SER, which is currently expected at the beginning of December 2023.

Common Action Items from BWRVIP-18-R2-A, -25-R1-A, -26-A, -27-A, -38, -41-R4-A, -42-R1-A, -47-A, -48-R2, -49-A, -74-A, -76-R1-A	
Action Item Description	**Browns Ferry Response**
BWRVIP-All (1) The license renewal applicant is to verify that its plant is bounded by the report. Further, the renewal applicant is to commit to programs described as necessary in the BWRVIP reports to manage the effects of aging of subject components during the period of extended operation. Applicants for license renewal will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the aging management programs within these BWRVIP reports described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the components or other information presented in the reports, such as materials of construction, will have to be identified by the renewal applicant and evaluated on a plant specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).	The BWRVIP reports applicable to BFN have been reviewed and BFN aging management programs have been verified to be bounded by the reports. Additionally, BFN is committed to programs described as necessary in the BWRVIP reports to manage the effects of aging during the subsequent period of extended operation. These commitments are included in SLRA Appendix A, Section A.5.0. If, upon review of a BWRVIP approved guideline, it is determined that known deviations to full compliance are warranted, the NRC will be notified of the deviation within 45 days of the receipt of NRC final approval of the guideline. Commitments are administratively controlled in accordance with the requirements of TVA/BFN procedures.
BWRVIP-All (2) 10 CFR 54.21(d) requires that an FSAR supplement for the facility contains a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation. Those applicants for license renewal referencing the applicable BWRVIP report shall ensure that the programs and activities specified as necessary in the applicable BWRVIP reports are summarily described in the FSAR supplement.	The FSAR supplements are included in SLRA Appendix A. The FSAR supplements include a summary description of the programs and activities specified as necessary for managing the effects of aging per the BWRVIP reports.

Common Action Items from BWRVIP-18-R2-A, -25-R1-A, -26-A, -27-A, -38, -41-R4-A, -42-R1-A, -47-A, -48-R2, -49-A, -74-A, -76-R1-A (Continued)	
Action Item Description	**Browns Ferry Response**
BWRVIP-All (3) 10 CFR 54.22 requires that each application for license renewal include any technical specification changes (and the justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the renewal application. The applicable BWRVIP reports may state that there are no generic changes or additions to technical specifications associated with the report as a result of its aging management review and that the applicant will provide the justification for plant specific changes or additions. Those applicants for license renewal referencing the applicable BWRVIP report shall ensure that the inspection strategy described in the reports does not conflict with or result in any changes to their technical specifications. If technical specification changes or additions do result, then the applicant must ensure that those changes are included in its application for license renewal.	There are no changes to technical specifications that are required to meet the requirements of the BWRVIP reports during the subsequent period of extended operation. Reference SLRA Appendix D.

Additional Action Items	
BWRVIP-18-Revision 2A, Core Spray Internals Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Browns Ferry Response**
BWRVIP-18 (4) Applicants referencing the BWRVIP-18 report for license renewal should identify and evaluate any potential TLAA issues which may impact the structural integrity of the subject RPV core spray internal components.	Cumulative fatigue damage is a potential TLAA issue identified for core spray system piping and components internal to the reactor vessel. TLAA is used to manage cumulative fatigue damage for these core spray piping and components as discussed in Sections 4.3.9 and 4.3.10.

Additional Action Items	
BWRVIP-25-R1-A Core Plate Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Browns Ferry Response**
BWRVIP-25-R1-A (4) Due to susceptibility of the rim hold-down bolts to stress relaxation, applicants referencing the BWRVIP-25 report for license renewal should identify and evaluate the projected stress relaxation as a potential TLAA issue.	Preload of the rim hold-down bolts is required to prevent lateral motion of the core plate for those plants, including BFN, that do not have core plate wedges installed. Stress relaxation of the reactor vessel core plate rim hold-down bolts has been identified as a TLAA issue as evaluated in Section 4.2.9.
BWRVIP-25-R1-A (5) Until such time as an expanded technical basis for not inspecting the rim hold-down bolts is approved by the staff, applicants referencing the BWRVIP-25 report for license renewal should continue to perform inspections of the rim hold-down bolts.	As evaluated in BWRVIP-25-R1-A Appendix I, rim hold-down bolt inspections are not required as documented in Section 4.2.9.

Additional Action Items	
BWRVIP-26-A Top Guide Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Browns Ferry Response**
BWRVIP-26-A (4) Due to IASCC susceptibility of the subject safety-related components, applicants referencing the BWRVIP-26 report for license renewal should identify and evaluate the projected accumulated neutron fluence as a potential TLAA issue.	The fluence evaluation for the top guide performed for BFN license renewal determined that the neutron fluence threshold for IASCC susceptibility would be exceeded at the end of the initial period of extended operation. As such, baseline inspections of the top guide grid beam were performed in U1R10, U2R11, and U3R9. Fluence for reactor internals is evaluated as a TLAA in Sections 4.2.1 and 4.2.14. During the subsequent period of extended operation, the aging of the top guide will be managed by inspections conducted as part of the BWR Vessel Internals program (B.2.1.7) per guidance provided in BWRVIP-183-A. The program requires that at least 10 percent of the grid beam cells containing control rod blades will be inspected every 12 years with at least 5 percent to be performed within the first 6 years. This has been completed for the first 12-year period in all three BFN units. The inspections are performed using the enhanced visual inspection technique, EVT-1. The program also allows for inspections to be performed using UT once it becomes available. Inspections will continue to be performed as described above during the subsequent period of extended operation.

Additional Action Items	
BWRVIP-27-A Standby Liquid Control System/Core Plate dP Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Browns Ferry Response**
BWRVIP-27-A (4) Applicants referencing the BWRVIP-27-A report for license renewal should identify and evaluate the projected fatigue cumulative usage factors as a potential TLAA issue.	Cumulative fatigue damage is a potential TLAA issue identified for the SLC system/core plate dP penetration. TLAA is used to manage cumulative fatigue damage for the SLC system/core plate dP penetration as discussed in Sections 4.3.1 and 4.3.3.

Additional Action Items	
BWRVIP-42-R1-A, BWR LPCI Coupling Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Browns Ferry Response**
BWRVIP-42-A (4) Applicants referencing the BWRVIP-42 report for license renewal should identify and evaluate any potential TLAA issues which may impact the structural integrity of the subject RPV internal components.	BFN design does not include LPCI couplings; this action item does not apply.
BWRVIP-42-A (5) The BWRVIP committed to address development of the technology to inspect inaccessible welds and to have the individual LR applicant notify the NRC of actions planned. Applicants referencing BWRVIP-42 report for license renewal should identify the action as open and to be addressed once the BWRVIP's response to this issue has been reviewed and accepted by the staff.	BFN design does not include LPCI couplings; this action item does not apply.

Additional Action Items	
BWRVIP-47-A, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Browns Ferry Response**
BWRVIP-47-A (4) Due to fatigue of the subject safety-related components, applicants referencing the BWRVIP-47 report for LR should identify and evaluate the projected CUF as a potential TLAA issue.	Fatigue usage is considered a TLAA for reactor vessel in-core instrumentation penetrations and CRD penetrations. This is addressed in Sections 4.3.1, 4.3.2, and 4.3.3.

Additional Action Items	
BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Browns Ferry Response**
BWRVIP-74-A (4) The staff is concerned that leakage around the reactor vessel seal rings could accumulate in the VFLD lines, cause an increase in the concentration of contaminants and cause cracking in the VFLD line. The BWRVIP-74 report does not identify this component as within the scope of the report. However, since the VFLD line is attached to the RPV and provides a pressure boundary function, LR applicants should identify an AMP for the VFLD line.	The vessel flange leak detection (VFLD) nozzles and piping are included in the scope of scope of subsequent license renewal. The nozzles are made from carbon steel and nickel alloy. Loss of material is managed by the One-Time Inspection program (B.2.1.20) and the Water Chemistry program (B.2.1.2). The VFLD piping is fabricated from stainless steel. Cracking is managed by the One-Time Inspection program (B.2.1.20), the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program (B.2.1.1) and the Water Chemistry program (B.2.1.2). Loss of material is managed by the One-Time Inspection program (B.2.1.20).
BWRVIP-74-A (5) LR applicants shall describe how each plant specific aging management program addresses the following elements: (1) scope of program, (2) preventative actions, (3) parameters monitored and inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.	There are no plant-specific aging management programs credited for managing aging of reactor vessel components. Descriptions of the aging management programs credited for managing the reactor vessel are described in Appendix B. These descriptions include any program element that deviates from the NUREG-2191 program element, and any enhancements that are required to meet NUREG-2191 requirements.
BWRVIP-74-A (6) The staff believes inspection by itself is not sufficient to manage cracking. Cracking can be managed by a program that includes inspection and water chemistry. BWRVIP-29 describes a water chemistry program that contains monitoring and control guidelines for BWR water that is acceptable to the staff. BWRVIP-29 is not discussed in the BWRVIP-74 report. Therefore, in addition to the previously discussed BWRVIP reports, LR applicants shall contain water chemistry programs based on monitoring and control guidelines for reactor water chemistry that are contained in BWRVIP-29.	The Water Chemistry program (B.2.1.2) is consistent with NUREG-2191, Revision 0, Chapter, XI.M2, “Water Chemistry,” and meets the requirements of the latest BWRVIP Water Chemistry guidelines to help ensure the long-term integrity of the reactor vessel and internals. Aging management programs that utilize inspections to perform condition monitoring of reactor vessel and internal components to identify cracking also credit the Water Chemistry program to mitigate cracking of reactor vessel components, including the BWR Vessel Internals program (B.2.1.7), BWR Vessel ID Attachment Welds program (B.2.1.4), BWR Penetrations program (B.2.1.6), and BWR Stress Corrosion Cracking program (B.2.1.5).
BWRVIP-74-A (7) LR applicants shall identify their vessel surveillance program, which is either an ISP or plant-specific in-vessel surveillance program, applicable to the LR term.	The Reactor Vessel Material Surveillance program (B.2.1.19) will utilize the Boiling Water Reactor Vessel and Internals Project, Plan for Extension of the BWR Integrated Surveillance (ISP) Through the Second License Renewal (SLR) program per BWRVIP-321 Revision 1-A for the subsequent period of extended operation.

Additional Action Items	
BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines (Continued)	
Action Item Description	**Browns Ferry Response**
BWRVIP-74-A (8) LR applicants should verify that the number of cycles assumed in the original fatigue design is conservative to assure that the estimated fatigue usage for 60 years of plant operation is not underestimated. The use of alternative actions for cases where the estimated fatigue usage is projected to exceed 1.0 will require case-by-case staff review and approval. Further, a LR applicant must address environmental fatigue for the components listed in the BWRVIP-74 report for the LR period.	The Metal Fatigue Analyses associated with the reactor vessel are evaluated as TLAAs in Section 4.3.2. Fatigue TLAAs are managed by the Fatigue Monitoring program (B.3.1.1) to ensure that cumulative fatigue usage will not exceed 1.0. Environmental fatigue for reactor vessel components is evaluated in Section 4.3.5.
BWRVIP-74-A (9) Appendix A to the BWRVIP-74 report indicates that a set of P-T curves should be developed for the heat-up and cool-down operating conditions in the plant at a given EFPY in the LR period.	P-T limit curves will be developed per 10 CFR 50, Appendix G requirements for the subsequent period of extended operation as discussed in Section 4.2.4, and will be submitted to the NRC prior to exceeding the current 38 EFPY limits for Unit 1, 48 EFPY limits for Unit 2, and 54 EFPY limits for Unit 3.
BWRVIP-74-A (10) To demonstrate that the beltline materials meet the Charpy USE criteria specified in Appendix B of the report, the applicant shall demonstrate that the percent reduction in Charpy USE for their beltline materials are less than those specified for the limiting BWR/3-6 plates and the non-Linde 80 submerged arc welds and that the percent reduction in Charpy USE for their surveillance weld and plate are less than or equal to the values projected using the methodology in RG 1.99, Revision 2.	Charpy upper-shelf energy (USE) values for the subsequent period of extended operation were determined using methods consistent with Regulatory Guide (RG) 1.99, Revision 2. This is discussed as a TLAA in Section 4.2.2.

Additional Action Items	
BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines (Continued)	
Action Item Description	**Browns Ferry Response**
BWRVIP-74-A (11) To obtain relief from the in-service inspection of the circumferential welds during the LR period, the BWRVIP report indicates each licensee will have to demonstrate that (1) at the end of the renewal period, the circumferential welds will satisfy the limiting conditional failure frequency for circumferential welds in the Appendix E for the staff's July 28, 1998, FSER, and (2) that they have implemented operator training and established procedures that limit the frequency of cold overpressure events to the amount specified in the staff's FSER.	BWRVIP-05 and its associated NRC 1998 Final Safety Evaluation Report (FSER) provides the technical basis for the elimination of ASME Code, Section XI examination of reactor vessel circumferential welds and the reduction of examination of reactor vessel axial welds for BWRs. However, the scope and evaluation for BWRVIP-05 was limited to 40 years of plant operation. BFN previously applied for, and had been granted relief from reactor vessel circumferential weld inspection for the Unit 2 vessel and for the Unit 3 vessel, as described in the NRC Safety Evaluation dated March 14, 2012. BFN also applied for and received relief for Unit 1, as described in NRC Safety Evaluation dated February 17, 2016. Subsequently, BWRVIP-329-A and the associated NRC Safety Evaluation provide additional technical basis for reduction in inspection of reactor vessel circumferential welds and an assessment of axial weld integrity for extended operations of up to 80 years. BWRVIP-329-A provides criteria for applicability based on plant-specific data. The Units 1, 2, and 3 reactor vessel circumferential weld failure probability analyses have been projected through the subsequent period of extended operation. The plant-specific information described in Section 4.2.5 demonstrates that, at the end of the subsequent period of extended operation, the BFN Units 1, 2, and 3 circumferential beltline weld materials will meet the applicability criteria for limiting plates and circumferential welds in BWRVIP-329-A. A request for relief from circumferential weld examination during the subsequent period of extended operation will be made in accordance with 10 CFR 50.55a(a)(3) for NRC review and approval prior to entering the subsequent period of extended operation. BFN procedures have been established for overpressure events and operator training was originally committed to at BFN as part of BWRVIP-05 implementation.

Additional Action Items	
BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines (Continued)	
Action Item Description	**Browns Ferry Response**
BWRVIP-74-A (12) As indicated in the staff's March 7, 2000, letter to Carl Terry, a LR applicant shall monitor axial beltline weld embrittlement. One acceptable method is to determine that the mean RT_{NDT} of the limiting axial beltline weld at the end of the period of extended operation is less than the values specified in Table 1 of this FSER.	The Axial Weld Failure Probability Assessment Analyses have been identified as TLAAs that are evaluated in Section 4.2.6.
BWRVIP-74-A (13) The Charpy USE, P-T limit, circumferential weld and axial weld RPV integrity evaluations are all dependent upon the neutron fluence. The applicant may perform neutron fluence calculations using staff approved methodology or may submit the methodology for staff review. If the applicant performs the neutron fluence calculation using a methodology previously approved by the staff, the applicant should identify the NRC letter that approved the methodology.	An NRC approved methodology was used to determine fluence during the subsequent period of extended operation, as discussed in Sections 4.2.1.1 and 4.2.1.2.

Additional Action Items	
BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines (Continued)	
Action Item Description	**Browns Ferry Response**
BWRVIP-74-A (14) Components that have indications that have been previously analytically evaluated in accordance with sub-section IWB-3600 of Section XI to the ASME Code until the end of the 40-year service period shall be reevaluated for the 60-year service period corresponding to the LR term.	Components within the ASME Code Class 1 reactor coolant pressure boundary with indications that have been previously analytically evaluated until the end of the initial period of extended operation are evaluated to the end of the subsequent period of extended operation. During BFN Unit 2 refuel outage 21 (U2R21), ultrasonic examination of the BFN Unit 2 reactor vessel, an indication in a vertical weld (V-3-A) was identified that exceeds the acceptance standards of ASME Code, Section XI, IWB-3500. A flaw evaluation per the requirements of IWB-3600 was required. Based on the flaw evaluation of the indication in the BFN Unit 2 reactor vessel V-3-A vertical weld using ASME Code Section XI, IWB-3600, it will take 84 years for the as-found flaw with an initial half-depth of 1.6 inch to propagate to the allowable half-depth of 1.7156 inch based on the 64 EFPY fluence at the end of the subsequent period of extended operation. Acceptable margin to the allowable flaw size will be verified as part of ongoing periodic ASME Code Section XI Inservice Inspections. The effects of aging on the intended function of the reactor vessel vertical weld V-3-A will be adequately managed through ongoing periodic ASME Code Section XI Inservice Inspections, per 10 CFR 54.21(c)(1)(iii). Refer to Section 4.7.3.

Additional Action Items	
BWRVIP-76-R1-A, BWR Core Shroud Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Browns Ferry Response**
BWRVIP-76-R1-A (4) The applicant shall reference the NRC staff approved TRs BWRVIP-14-A, BWRVIP-99 (when approved) and BWRVIP-100-A in their RVI AMP. The applicant shall make a statement in their LRA that the crack growth rate evaluations and fracture toughness values specified in these reports shall be used for cracked core shroud welds that are exposed to the neutron fluence values that are specified in these TRs. The applicant shall confirm that they will incorporate any emerging inspection guidelines developed by the BWRVIP for these welds.	The BFN BWR Vessel Internals program (B.2.1.7) implements BWRVIP-76, Revision 1-A requirements including guidance within BWRVIP-76, Revision 1-A Section D to use current NRC-approved BWRVIP guidance to determine crack growth rates and fracture toughness values, which specifically includes BWRVIP-14-A, BWRVIP-99-A, and BWRVIP-100-A for evaluation of crack growth and fracture toughness. The implementing procedures for the BFN BWR Vessel Internals program include guidance to incorporate new guidance within new or revised BWRVIP reports. This assures that any emerging inspection guidelines developed by the BWRVIP for these core shroud welds will be incorporated into the program. Core shroud crack growth TLAAs are discussed in Section 4.2.14.
BWRVIP-76-R1-A (5) LR applicants that have core shrouds with tie rod repairs shall make a statement in their AMP associated with RVI components that they have evaluated the implications of the Hatch Unit 1 tie rod repair cracking on their units and incorporated revised inspection guidelines, if any, developed by the BWRVIP.	The BFN core shrouds have not been modified to include tie rod repairs.

Additional Action Items	
BWRVIP-76-R1-A, BWR Core Shroud Inspection and Flaw Evaluation Guidelines (Continued)	
Action Item Description	**Browns Ferry Response**
BWRVIP-76-R1-A (6) The NRC staff's guidance in Table IV.B1 of the GALL Report lists two potentially applicable aging effects (i.e., in addition to cracking) for generic BWR reactor vessel internal components (including BWR core shroud and core shroud repair assembly components) that are made from either stainless steel (including CASS) or nickel alloy: (1) loss of material due to pitting and crevice corrosion (Refer to GALL AMR IV.B1- 15), and (2) cumulative fatigue damage (Refer to AMR Item IV.B1-14). BWR LR applicants will need to assess their designs to see if the generic guidelines for managing cumulative fatigue damage in GALL AMR item IV.B1-14 and for management of loss of material due to pitting and crevice corrosion in GALL AMR IV.B1-15 are applicable to the design or their core shroud components (including welds) and any core shroud assembly components that have been installed through a design modification of the plant. If these aging affects are applicable to the design of these components as a result of exposing them to a reactor coolant with integrated neutron flux environment, applicants for license renewal will need to: (1) identify the aging effects as aging effects requiring management (AERM) for the core shrouds and for their core shroud assembly components if a repair design modification has been implemented, and (2) identify the specific aging management programs or time-limited aging analyses that will be used to manage these aging effects during the period of extended operation. Refer to License Renewal Applicant Action Item 7) for additional guidance on identifying the AERMs for core shroud components or core shroud repair assembly components that are made from materials other than stainless steel (including CASS) or nickel alloy.	The BFN core shrouds (including welds) are fabricated from stainless steel and nickel alloy material. Cumulative fatigue damage analyses for the limiting ASME Section III Class 1 components have been identified as TLAAs as discussed in Section 4.3.2. In addition to cracking, loss of material due to pitting and crevice corrosion and cumulative fatigue damage are identified as applicable aging effects for the core shrouds requiring aging management. The BWR Vessel Internals program (B.2.1.7) and Water Chemistry (B.2.1.2) program will be used to manage cracking and loss of material due to pitting and crevice corrosion during the subsequent period of extended operation.
BWRVIP-76-R1-A (7) For BWR LRAs identification of AERMs for core shroud components or core shroud repair assembly components that are made from materials other than stainless steel (including CASS) or nickel alloy will need to be addressed on a plant-specific basis that is consistent with the Note format criteria for plant-specific AMR items in the latest NRC approved version TR NEI-95-10.	The core shrouds (including welds) are fabricated from stainless steel and nickel alloy material. No core shroud repair assembly components have been added. Therefore, core shroud components that are made from materials other than stainless steel or nickel alloy are not addressed.

Additional Action Items	
BWRVIP-76-R1-A, BWR Core Shroud Inspection and Flaw Evaluation Guidelines (Continued)	
Action Item Description	**Browns Ferry Response**
BWRVIP-76-R1-A (8) LR applicant shall reference the NRC staff approved topical reports BWRVIP-99 and BWRVIP-100-A in their RVI components AMP.	The BWR Vessel Internals program (B.2.1.7) implements BWRVIP-76-R1-A requirements including guidance within BWRVIP-76-R1-A Section D to use current NRC-approved BWRVIP guidance to determine crack growth rates and fracture toughness values. The current implementing procedure guidance includes letter 2012-074 from Randy Stark, EPRI, BWRVIP Program Manager, to All BWRVIP Committee Members, Superseded “Needed” Guidance Regarding Crack Growth Assumptions, March 22, 2012 for evaluation of crack growth rates in austenitic stainless steel and nickel based alloy components. This guidance is consistent with BWRVIP-14-A and BWRVIP-99-A. The Aging Management Program Basis Document and implementing procedures for the BWR Vessel Internals program (B.2.1.7) are being enhanced prior to the subsequent period of extended operation to explicitly include reference to applicable BWRVIP reports including BWRVIP-14-A, BWRVIP-99-A, and BWRVIP-100-A for evaluation of crack growth.

BWRVIP-139-R1-A, Steam Dryer Inspection and Flaw Evaluation Guidelines	
Action Item Description	**Browns Ferry Response**
BWRVIP-139-R1-A (1) Aging Effects and Mechanisms Not Assessed or Managed in TR No. BWRVIP-139-R1-A, Appendix B-Plant-Specific Design Differences or Operating Experience Considerations The regulation in 10 CFR 54.21(a)(3) requires a license renewal applicant to manage all aging effects that are applicable to those plant components that have been scoped in for license renewal in accordance with 10 CFR 54.4 and have been screened in for an AMR in accordance with 10 CFR 54.21(a)(1). Guidelines for identifying applicable aging effects are given in Section A.1.2.1 of NUREG-1800, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants” (SRP-LR, with the current version being Revision 2 of the report), and in TR No. NEI 95-10 (current NRC endorsed version of the report is Revision 6 of the NEI report. a. BWR applicants for license renewal are requested to perform a review of the CLB and design basis of their facilities to determine whether there are any design differences in their steam dryer designs or steam dryer related OE that is applicable for their BWR design. Specifically, BWR applicants for license renewal are requested to perform a review of the CLB and design basis of their facilities to determine whether there are any additional aging effects/mechanisms that might be applicable to the designs of their BWR steam dryer assemblies, in addition to those that are mentioned as being applicable aging effects/mechanisms requiring management (AERMs) in BWRVIP-139-R1-A, Appendix B. b. For those BWR license renewal applicants that identify additional AERMs beyond those listed in BWRVIP-139-R1-A, Appendix B, the applicants should include applicable GALL-based or plant-specific AMR items in the LRAs that identify the additional aging effects that are applicable to their steam dryer designs, and should identify and justify the AMP or TLAA that will be used to manage those aging effects during the period of extended operation, as required by 10 CFR 54.21(a)(3).	Replacement Steam Dryers (RSD), designed and manufactured by GE-Hitachi Nuclear Energy (GEH) with a design life of 40 years, were installed in Unit 3 during Unit 3 Refueling Outage 18 (U3R18) in the Spring of 2018, in Unit 1 during Unit 1 Refueling Outage 12 (U1R12) in the Fall of 2018, and in Unit 2 during Unit 2 Refueling Outage 20 (U2R20) in the Spring of 2019 in preparation for Extended Power Uprate (EPU) implementation during each unit’s subsequent operating cycle. There are no physical differences between the three RSDs. While these RSDs maintain the same general configuration and function as the original steam dryers, there are considerable differences in design, material, and manufacturing details between the original steam dryers and the RSDs, primarily aimed at improving corrosion resistance and managing fatigue loads. The RSDs were built consistent with the design, materials requirements, and fabrication controls of BWRVIP-181-A and BWRVIP-84. The BFN RSD materials were specifically selected to be resistant to corrosion and stress corrosion cracking in the BWR steam/water environment in compliance with the guidance of BWRVIP-84 and BWRVIP-181-A. The original steam dryers were all fabricated using Type 304 Stainless Steel. The dryer vanes of the original steam dryers were manufactured by Peerless and the assemblies were manufactured by Willamette Iron & Steel Company. The scope and applicability of the BWRVIP-139, Revision 1-A report, including Appendix B, only apply to the types of BWR steam dryer designs assessed in the BWRVIP-139, Revision 1-A report and do not apply to other steam dryer assemblies whose designs are outside the scope of those assessed in the report. BWRVIP-139, Revision 1-A assesses the original BFN steam dryers as described in Section 2.3.9 of the report. While the RSDs maintain the same general configuration and function as the original steam dryers, the considerable differences in design, materials, and manufacturing details render the BFN RSDs to be outside the scope of those dryers assessed in BWRVIP-139, Revision 1-A, and therefore it is not applicable to the RSDs per Limitation No. 1.

BWRVIP-139-R1-A, Steam Dryer Inspection and Flaw Evaluation Guidelines (Continued)	
Action Item Description	**Browns Ferry Response**
BWRVIP-139-R1-A (1) (continued)	Long term inspections recommended for aging management of the RSDs have been specified by GEH in GE-Hitachi Nuclear Energy Report No. 007N4785 - Revision 0, “Browns Ferry Nuclear Station (BFNS) - Recommendations for Future Inspections - Replacement Steam Dryer,” dated November 2022, which was subsequently submitted to the NRC (Letter from TVA to NRC, “Long Term Steam Dryer Inspection Plan,” dated January 20, 2023) pursuant to Unit 1 Operating License Condition 2.C(18)(i), Unit 2 Operating License Condition 2.C(18)(i), and Unit 3 Operating License Condition 2.C(14)(g) which required that a long term steam dryer inspection plan be submitted based on industry operating experience.

BWRVIP-139-R1-A, Steam Dryer Inspection and Flaw Evaluation Guidelines (Continued)	
Action Item Description	**Browns Ferry Response**
BWRVIP-139-R1-A (2) Referencing of the BWRVIP-139-R1-A Report and Appendix B of the Report in the FSAR, UFSAR, or USAR Supplement For demonstration of the requirement in 10 CFR 54.21(d), BWR license renewal applicants applying the BWRVIP-139-R1-A report and Appendix B of the report to manage age-related degradation in their BWR steam dryer assemblies shall describe or reference in the applicable FSAR, UFSAR, or USAR supplement summary description for the AMP how the BWRVIP-139-R1-A report and Appendix B of the report will be used to manage aging in the plant's steam dryer assembly components during the period of extended operation.	The scope and applicability of the guidance provided in BWRVIP-139, Revision 1-A report, including Appendix B, only apply to the types of BWR steam dryer designs that are assessed in the BWRVIP-139, Revision 1-A report and do not apply to other steam dryer assemblies whose designs are outside the scope of those assessed in the report. BWRVIP-139, Revision 1-A assesses the original BFN steam dryers as described in Section 2.3.9 of the report. RSDs designed and manufactured by GEH with a design life of 40 years were installed in Unit 3 during U3R18 in the Spring of 2018, in Unit 1 during U1R12 in the Fall of 2018, and in Unit 2 during U2R20 in the Spring of 2019 in preparation for EPU implementation during each unit's subsequent operating cycle. While the RSDs maintain the same general configuration and function as the original steam dryers, the considerable differences in design, materials, and manufacturing details render the BFN RSDs to be outside the scope of those dryers assessed in BWRVIP-139, Revision 1-A, and therefore it is not applicable to the RSDs per Limitation No. 1. GEH provided recommendations for future inspections of the RSDs in GE-Hitachi Nuclear Energy Report No. 007N4785 - Revision 0, "Browns Ferry Nuclear Station (BFNS) - Recommendations for Future Inspections - Replacement Steam Dryer," dated November 2022, which was subsequently submitted to the NRC (Letter from TVA to NRC, "Long Term Steam Dryer Inspection Plan," dated January 20, 2023) pursuant to Unit 1 Operating License Condition 2.C(18)(i), Unit 2 Operating License Condition 2.C(18)(i), and Unit 3 Operating License Condition 2.C(14)(g) which required that a long term steam dryer inspection plan be submitted based on industry operating experience.

BWRVIP-139-R1-A, Steam Dryer Inspection and Flaw Evaluation Guidelines (Continued)	
Action Item Description	**Browns Ferry Response**
BWRVIP-139-R1-A (2) (continued)	Because the RSD design, and the materials and fabrication processes utilized, are expected to result in significantly improved resistance to stress corrosion cracking, the GEH long term inspection recommendations in 007N4785 Rev. 0 focus primarily on the locations that may be susceptible to fatigue from flow-induced vibration. The locations identified are those indicated to have relatively significant cyclic loading during the dryer's operation, as determined by detailed stress analyses. The bases for these inspection recommendations from GEH includes: (1) typical BWR practice, engineering judgment considering prior EPU experience, experience with original equipment steam dryers, and industry recommendations (BWRVIP-139-R1-A), (2) fatigue cracking experience with BWR steam dryers (GE SIL-664), (3) the additional weight of the RSD relative to the original equipment steam dryer, suggesting the need for additional attention to potential damage in the region of the steam dryer support lugs, and (4) removal locations of Flow Induced Vibration instrumentation and plug installations (Unit 3 dryer only). The resolution standard for these visual examinations are "best effort VT-1" in accordance with BWRVIP-139-R1-A. Because there are not specific VT-3 resolution requirements per BWRVIP-139-R1-A, the resolution requirements of the recommended VT-3 examinations are the same as those for VT-1. The BWR Vessel Internals program (B.2.1.7) will be used to manage cracking due to flow-induced vibration, SCC, IGSCC, and loss of material due to wear. Loss of material due to corrosion or erosion of the stainless steel steam dryer materials is not an aging effect requiring management. Corrosion is adequately managed by the Water Chemistry program (B.2.1.2). Water chemistry controls implemented consistent with EPRI BWR Water Chemistry Guidelines limit impurities that could contribute to localized corrosion. Stainless steels are generally resistant to steam erosion. Operating history to date confirms that significant loss of material due to corrosion and erosion is not occurring in the field.

BWRVIP-139-R1-A, Steam Dryer Inspection and Flaw Evaluation Guidelines (Continued)	
Action Item Description	**Browns Ferry Response**
BWRVIP-139-R1-A (2) (continued)	Aging effects associated with irradiation induced degradation (i.e. irradiation embrittlement, IASCC, and irradiation induced stress relaxation) are not aging effects requiring management for the steam dryer. The steam dryer is located high in the reactor vessel, away from the core. Loss of fracture toughness due to thermal aging is not an aging effect requiring management for the steam dryer. Significant reductions in fracture toughness that could challenge the structural integrity of the steam dryer are not plausible. As previously mentioned, high cycle fatigue (HCF) is a concern for steam dryers. This concern is elevated for plants that have implemented EPU (hence the need for installing the RSDs prior to EPU). HCF damage occurs relatively quickly because of the typical cyclic frequencies involved. Therefore, if a steam dryer has operated at steady flow conditions for an extended time and inspections have revealed no cracking, the expectation is that the steam dryer will continue to operate indefinitely without new fatigue cracks occurring. The GEH long term inspection plan recognizes this and defines inspections and re-inspection intervals accordingly. Application of the GEH long term inspection regimen prescribed in 007N4785 Rev. 0 is adequate to manage the potential for fatigue failures occurring during the subsequent period of extended operation. There is no direct time dependency applicable to operations during the subsequent period of extended operation. Therefore, the guidance provided in the Long Term Steam Dryer Inspection Plan, GEH Report 007N4785 Rev. 0, along with the BWR Vessel Internals aging management program (B.2.1.7) and the Water Chemistry program (B.2.1.2) will be used to manage age-related degradation in the BFN replacement steam dryer assemblies, and as a result, the FSAR will not contain a summary description in the description of the BWR Vessel Internals program (B.2.1.7) for how the BWRVIP-139-R1-A report and Appendix B of the report will be used to manage aging in the plant's steam dryer assembly components during the subsequent period of extended operation.

BWRVIP-139-R1-A, Steam Dryer Inspection and Flaw Evaluation Guidelines (Continued)	
Action Item Description	**Browns Ferry Response**
BWRVIP-139-R1-A (3) Identification of Time Limited Aging Analyses License renewal applicants are required by 10 CFR 54.21(c)(1) to identify all analyses in the CLB that conform to the six criteria in 10 CFR 54.3(a) for defining an analysis as a TLAA. For those BWR license renewal applicants that confirm that the CLB includes a steam dryer analysis and the analysis conforms to the definition of TLAA, the applicants shall: a. include the TLAA in the LRA in accordance with the requirements in 10 CFR 54.21(c)(1) b. demonstrate that the TLAA will be acceptable for the period of extended operation in accordance with one of three criteria for accepting TLAAs in 10 CFR 54.21(c)(1)(i), (ii), or (iii), and c. include a FSAR, UFSAR or USAR supplement summary description for the TLAA in the LRA, in accordance with 10 CFR 54.21(d). These bases are consistent with the guidelines for formatting LRAs in NEI 95-10, Revision 6.	The steam dryers were added to the scope of License Renewal per the TVA response to NRC RAI 3.1-1 in TVA letter to the NRC dated January 31, 2005 and they are scoped and screened into Subsequent License Renewal (Section 2.2 and Section 2.3.1.2, respectively). The aging management program for the steam dryers for the subsequent period of extended operation is described in the BWR Vessel Internals program (B.2.1.7). The reactor vessel steam dryers were replaced on each BFN unit to support the EPU project. The BFN Units 1, 2, and 3 replacement steam dryers, designed and manufactured by GEH with a design life of 40 years, were installed in Unit 3 during Unit 3 Refueling Outage 18 (U3R18) in the Spring of 2018, in Unit 1 during Unit 1 Refueling Outage 12 (U1R12) in the Fall of 2018, and in Unit 2 during Unit 2 Refueling Outage 20 (U2R20) in the Spring of 2019 in preparation for EPU implementation during each unit's subsequent operating cycle. Since the evaluation for the new replacement steam dryers assumed a certain number of stress cycles during the design life, it has been identified as a TLAA that must be re-evaluated for the subsequent period of extended operation. Refer to SLRA Section 4.3.6. Since the subsequent period of extended operation for Unit 1 will end on December 20, 2053, Unit 2 on June 28, 2054, and Unit 3 on July 2, 2056, none of the replacement steam dryers will have exceeded their 40 year design lifetimes at the end of the subsequent period of extended operation. Given the 40-60 year period assumed in the structural analyses for the replacement steam dryers, the current structural analysis documented in NEDC-33824P would remain valid as follows: • until at least 2058 for the Unit 1 replacement steam dryer; • until at least 2058 for the Unit 3 replacement steam dryer; and • until at least 2059 for the Unit 2 replacement steam dryer. Therefore, in accordance with 10 CFR 54.21(c)(1)(i), the NEDC-33824P replacement steam dryer fatigue evaluation remains valid through the subsequent period of extended operation.

BWRVIP-139-R1-A, Steam Dryer Inspection and Flaw Evaluation Guidelines (Continued)	
Action Item Description	**Browns Ferry Response**
BWRVIP-139-R1-A (3) (continued)	An FSAR summary description for the TLAA is incorporated in the BFN SLRA in accordance with 10 CFR 54.21(d) via SLRA Appendix A, Section A.4.3.6.

In addition to the currently existing applicant action items, BFN will implement the guidance in BWRVIP-315 to support extended operations. BWRVIP-315 includes proposed enhancements and revisions to the existing BWRVIP reports which are identified for operation beyond 60 years. Although the content contained in these reports may be such that improvements can be made to address the subsequent period of extended operation, the BWRVIP maintains that any such changes are not required to provide assurance of an adequate aging management program capable of addressing extended operations. These enhancements and revisions are noted in the table below, alongside the applicant action items. The recommended clarifications and enhancements identified below are provided for the purpose of fully communicating the current intent of each recommended clarification and enhancement. However, the exact wording ultimately incorporated into each BWRVIP guideline is subject to alteration to reflect new information from research and development programs or fleet operating experience. Editorial and formatting changes may also be made. The revisions and enhancements to the guidance documents will be incorporated as a routine part of BWRVIP activities (i.e., revisions will be incorporated when the identified reports are being revised for other purposes). However, all revisions addressing extended operations will be completed no later than 2 years prior to the first U.S. BWR operation beyond 60 years.

BWRVIP-315, Reactor Internals Aging Management Evaluation for Extended Operations	
Action Item Description	**Browns Ferry Response**
BWRVIP-26-A To implement the guidance in BWRVIP-315, BWRVIP-26-A needs enhancement and revision as shown in BWRVIP-315 in order to address operation beyond 60 years. These changes include a clarification of the fluence dependent limitations associated with flaw evaluations.	The guidance provided in BWRVIP-26-A regarding Top Guide flaw evaluations is already incorporated into the BWR Vessel Internals program (B.2.1.7) however, as this recommended change is clarifying in nature, there are no actions required to implement.
BWRVIP-41-R4-A To implement the guidance in BWRVIP-315, BWRVIP-41-R4-A needs enhancement and revision as shown in BWRVIP-315 in order to address operation beyond 60 years. These changes include editorial changes regarding the operating service life, a defined screening threshold of accumulated neutron fluence for CASS embrittlement (6 x10^{20} n/cm^2 (E > 1.0 MeV)) based on BWRVIP-234-A, fluence based limitations on jet pump hold-down beams due to irradiation enhanced stress relaxation, defined actions for components which exceed these fluence thresholds and limitations, and refined inspection exemption criteria.	Further evaluation subsection 3.1.2.2.13 evaluates the loss of fracture toughness due to neutron irradiation or thermal aging embrittlement in stainless steel (including cast austenitic stainless steel (CASS), wrought austenitic stainless steel, and nickel alloy (including X-750 alloy) reactor vessel internal components exposed to reactor coolant with neutron flux, using an embrittlement screening threshold consistent with the one to be added to BWRVIP-41-R4-A (6 x10^{20} n/cm^2 (E > 1.0 MeV)) and using the 80 year fluence data for each reactor vessel internal component in Section 4.2.1.2.

BWRVIP-315, Reactor Internals Aging Management Evaluation for Extended Operations (Continued)	
Action Item Description	**Browns Ferry Response**
BWRVIP-41-R4-A (continued)	The CASS reactor vessel internal components include, but are not limited to, the jet pump assembly (transition piece including elbow, inlet mixer, and diffuser collar), and the jet pump restrainer brackets. The aging effect of loss of fracture toughness due to thermal aging embrittlement and neutron irradiation embrittlement on these CASS components was specifically evaluated in BWRVIP-234: BWR Vessel and Internals Project, Thermal Aging and Neutron Embrittlement Evaluation of Cast Austenitic Stainless Steels for BWR Internals. The BWRVIP-234 evaluation determined that no supplemental (augmented) inspections, beyond those recommendations within the current BWRVIP reports were needed for these components to manage the aging effect of loss of fracture toughness due to thermal aging embrittlement and neutron irradiation embrittlement. The NRC staff in its final safety evaluation for BWRVIP-234 accepted this recommendation, as adequately managing loss of fracture toughness due to thermal embrittlement and irradiation embrittlement and any possible combined effects of the two, for components that do not exceed 6 $x10^{20}$ n/cm^2. For BFN Units 1, 2 and 3, all of the Jet Pump components and repair components on all three BFN units are projected to have peak neutron fluence values at the end of the subsequent period of extended operation that do not exceed 6 $x10^{20}$ n/cm^2 (E>1 MeV). Therefore, supplemental inspections or enhancements to the existing BWRVIP guidance are not necessary for the jet pump assemblies (transition piece including elbow, inlet mixer, and diffuser collar) and jet pump restrainer brackets. The neutron fluence analysis discussed in Section 4.2.1.2 also documents the fact that all of the Jet Pump components and repair components on all three BFN units are projected to have peak neutron fluence values at the end of the subsequent period of extended operation that do not exceed the neutron fluence thresholds for irradiation enhanced stress relaxation to be incorporated in BWRVIP-41-R4-A in newly added Section 3.2.7. Therefore, the enhancements and revisions to BWRVIP-41-R4-A identified in BWRVIP-315 are not needed for the subsequent period of extended operation at BFN.

BWRVIP-315, Reactor Internals Aging Management Evaluation for Extended Operations (Continued)	
Action Item Description	**Browns Ferry Response**
BWRVIP-47-A To implement the guidance in BWRVIP-315, BWRVIP-47-A needs enhancement and revision as shown in BWRVIP-315 in order to address operation beyond 60 years. These changes include editorial changes regarding the operating service life and appropriate flaw evaluation methodologies.	The guidance provided in BWRVIP-47-A regarding flaw evaluations is already incorporated into the BWR Vessel Internals program (B.2.1.7). However, as this recommended change is clarifying in nature, there are no actions required to implement.
BWRVIP-76-R2 To implement the guidance in BWRVIP-315, BWRVIP-76-R2 needs enhancement and revision as shown in BWRVIP-315 in order to address operation beyond 60 years. These changes include a clarification of the fluence dependent limitations associated with flaw evaluations for core shroud repair hardware.	BFN does not have core shroud repair hardware installed and therefore the enhancements and revisions are not currently applicable. The changes provided in BWRVIP-315 are intended for BWRVIP-76-R2 which is not implemented by BFN. BFN has implemented BWRVIP-76 R1-A.
BWRVIP-183-A To implement the guidance in BWRVIP-315, BWRVIP-183-A needs enhancement and revision as shown in BWRVIP-315 in order to address operation beyond 60 years. These changes include reporting requirements for flaw evaluations which do not conform to BWRVIP acceptance criteria.	The guidance to be provided in the clarifications and enhancements to BWRVIP-183-A regarding fracture mechanics evaluations is based on existing BWRVIP guidance documents that are already incorporated into the BWR Vessel Internals program (B.2.1.7). As these recommended changes are clarifying in nature, there are no actions required to implement.
BWRVIP-315 License Condition 1 Applicants for renewed operating licenses extending beyond 60 years applying Code Case N-889 to calculate IASCC crack growth rate must comply with the conditions in the latest edition of Regulatory Guide 1.147 incorporated by reference in 10 CFR 50.55a.	Per procedure 0-TPP-ENG-467, Revision 1, Inservice Inspection Program, Code Case N-889 is not applied at BFN. Therefore, this License Condition does not apply to BFN.

BWRVIP-315, Reactor Internals Aging Management Evaluation for Extended Operations (Continued)	
Action Item Description	**Browns Ferry Response**
BWRVIP-315 License Condition 2 Applicants for renewed operating licenses extending beyond 60 years must justify applicability for non-RAMA-based, plant-specific fluence evaluations. Alternatively, the BWRVIP may address the generic qualification to evaluate RVI component fluence for each fluence methodology in use at operating BWRs.	All the BFN specific neutron fluence analyses performed in support of the BFN SLRA were performed by TransWare Enterprises Inc. using the RAMA fluence methodology. The Neutron Fluence Monitoring program (B.3.1.2) requires that if any future neutron fluence analyses supporting operation in the subsequent period of extended operation which evaluate fluence in regions outside the immediate core adjacent area of the reactor vessel beltline using a Regulatory Guide 1.190-adherent methodology other than the RAMA methodology, appropriate justification of the application of the methodology with regard to such aspects as the level of detail used to represent the core neutron source, the methods to synthesize the three-dimensional flux field, and the order of angular quadrature used in the neutron transport calculations, and the applicability of existing qualification data will be documented, as required by NUREG-2191 Aging Management Program X.M2.
BWRVIP-315 Applicant Action Item 1 Applicants for renewed operating licenses extending beyond 60 years must demonstrate that their application of BWRVIP RVI guidelines adequately manages aging degradation in accordance with 10 CFR 54.21(a)(3), which may include accounting for up-to-date operating experience, industry guidance, and NRC guidance available at the time of the application.	Based on the NRC review of the BWRVIP RVI guidelines documented in its draft SER to BWRVIP-315, the NRC staff noted that to date, the following attributes have been implemented by the BWR fleet with respect to periodic RVI inspections: • Periodic inspections intervals are based on the time in service for a particular RVI component, • Inspection interval is determined by generic flaw tolerance evaluations, • Evaluation of inspection data, • Engineering judgment, • Components that are susceptible to degradation, and have low flaw tolerance are inspected more frequently, • Components that are less susceptible to degradation and have high tolerance are inspected less frequently; and • Based on the operating experience, inspection frequencies are increased, or new inspections are specified. The NRC staff determined that implementation of the above methodology related to periodic

BWRVIP-315, Reactor Internals Aging Management Evaluation for Extended Operations (Continued)	
Action Item Description	**Browns Ferry Response**
BWRVIP-315 Applicant Action Item 1 (continued)	inspection has been very effective in identifying aging degradation in a timely manner. Therefore, the proper corrective action can be taken in a timely fashion to minimize the aging effects on a given RVI component. Additionally, the functionality of the subject component can be maintained during the extended operations. The periodic inspections provide reasonable assurance that the RVI components would adequately maintain their functions during the extended operations. The NRC noted that during the extended operations, if there is a new aging degradation or if the cracking due to an existing degradation were to occur frequently, the licensees would revise the inspection criteria to ensure that the aging degradation would be adequately managed during the extended operations. The NRC found that any revision to inspection criteria based on the emerging or frequent occurrence of active degradation is essential to achieve prompt detection of the aging effects. Hence, the NRC found that implementation of this BWRVIP inspection criteria is acceptable for managing aging degradation. Additionally, an Effectiveness Review of the existing BWR Vessel Internals Aging Management Program was recently performed and documented in the BFN SLRA (B.2.1.7). The purpose of the review was to evaluate the effectiveness of the implementation actions taken during the period of extended operation for the BWR Vessel Internals Aging Management Program and to evaluate the expected effectiveness of the program during the subsequent period of extended operation. The evaluation of existing Aging Management Program activities provides documented evidence of how the current programs are managing the aging of in-scope components and structures during the period of extended operation. Programs that are currently being implemented effectively provides objective evidence, and reasonable assurance, that the aging of in-scope components and structures will continue to be effectively managed during the subsequent period of extended operation. The review was conducted in four steps. Step 1 consisted of a review of the fundamental basis

BWRVIP-315, Reactor Internals Aging Management Evaluation for Extended Operations (Continued)	
Action Item Description	**Browns Ferry Response**
BWRVIP-315 Applicant Action Item 1 (continued)	on which the BWR Vessel Internals Aging Management Program (AMP) was established (program commitments, development of the AMP Basis Document and program implementing procedures). Step 2 involved the identification and assessment of the results of the activities taken to satisfy the AMP. Step 3 was to perform a review of both plant-specific (internal) and industry (external) operating experience to ensure that the AMP is effective in managing the aging effects for which it is credited. Step 4 documented the results and conclusion on AMP effectiveness during the period of extended operation. The review concluded that the BWR Vessel Internals aging management program will provide reasonable assurance that the applicable aging effects will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the subsequent period of extended operation.
BWRVIP-315 Applicant Action Item 2 Applicants for renewed operating licenses extending beyond 60 years must describe whether the core plate hold-down bolt analysis per BWRVIP-25, Appendix I is a TLAA. If so, the applicant must include the analysis as a TLAA in the licensing application.	Stress relaxation of the reactor vessel core plate rim hold-down bolts has been identified as a TLAA issue as evaluated in Section 4.2.9. The TLAA in Section 4.2.9 describes the loss of preload for core plate rim hold-down bolts, and the evaluation concluded that the criteria of Appendix I of BWRVIP-25-R1-A are satisfied at BFN.
BWRVIP-315 Applicant Action Item 3 Applicants for renewed operating licenses extending beyond 60 years must describe and justify plant-specific re-inspection plans for the lower plenum in the application.	Inspections and evaluations of the lower plenum components are performed in accordance with BWRVIP-47-A. The guidance provided in BWRVIP-47-A regarding flaw evaluations is already incorporated into the BWR Vessel Internals program (B.2.1.7). Inspections required by BWRVIP-47-A relative to CRD housings are further discussed in the BWR Penetrations program (B.2.1.6). The repair design criteria in BWRVIP-55-A and BWRVIP-58-A would be utilized in preparing a repair plan for the control rod drive housings. Regarding lower plenum re-inspection requirements, Section 3.2.4 of BWRVIP-47-A states:

BWRVIP-315, Reactor Internals Aging Management Evaluation for Extended Operations (Continued)	
Action Item Description	**Browns Ferry Response**
BWRVIP-315 Applicant Action Item 3 (continued)	"Currently no additional inspections are recommended beyond the baseline inspections described in Section 3.2.2, and scope expansion and follow-on inspections deemed necessary in the event flaws are found as given in Section 3.2.3. Baseline inspection results will be reviewed by the BWRVIP and, if deemed necessary, re-inspection recommendations will be developed later and provided to the NRC." Although BWRVIP-47-A does not include periodic inspection requirements, the use of fluence thresholds consistent with BWRVIP-47-A and evaluation to assess periodic inspection needs should ensure adequate aging management. In Section 4.3.5.3 of BWRVIP-315, the BWRVIP stated that it will include the flaw evaluation guidance for locations subject to significant fluence i.e., CRGT-1. Furthermore, the BWRVIP stated that the revised I&E guidelines related to the emerging aging degradation due to IASCC and irradiation embrittlement in CRGTs and CRD housing during the subsequent period of extended operation will be included in the new revision to be published two years prior to the first BWR plant operating beyond 60 years.
BWRVIP-315 Applicant Action Item 4 Applicants for renewed operating licenses extending beyond 60 years must describe how they meet Limitation 3 in Section 4.5.1 of BWRVIP-315 in the application (repeated below). <u>Limitation 3 - CASS Embrittlement:</u> Jet pump and LPCI coupling CASS components subjected to fluence exceeding 6 x10^{20} n/cm^2 (E > 1.0 MeV) must be evaluated on a plant-specific basis or be included in a plant-specific aging management program. This limitation is based on the fluence criterion contained in BWRVIP-234-A. BWRVIP I&E guidelines affected include BWRVIP-41 and BWRVIP-42. (See Sections 4.3.8 and 4.3.10 of BWRVIP-315) for additional discussion. Appropriate changes to BWRVIP-41 to identify this limitation are included in Appendix B, Section B.1. Appropriate changes to BWRVIP-42 to identify and describe this limitation are included in Appendix B, Section B.2.	The Browns Ferry vessel internals do not include LPCI couplings, and as such this component is not applicable for evaluation. A further evaluation for Reactor Vessel, Internals, and Reactor Coolant System (Subsection 3.1.2.2.13) evaluates the loss of fracture toughness due to neutron irradiation or thermal aging embrittlement in stainless steel (including cast austenitic stainless steel (CASS), wrought austenitic stainless steel, and nickel alloy (including X-750 alloy) reactor vessel internal components exposed to reactor coolant with neutron flux, using an embrittlement screening threshold consistent with the one to be added to BWRVIP-41-R4-A (6 x10^{20} n/cm^2 (E > 1.0 MeV) and using the 80 year fluence data for each reactor vessel internal component in Section 4.2.1.2. The CASS reactor vessel internal components include, but are not limited to, the jet pump assembly (transition piece including elbow, inlet mixer, and diffuser collar), and the jet pump restrainer brackets. The aging effect of loss of fracture toughness due to thermal aging embrittlement and neutron irradiation embrittlement on these CASS components was specifically evaluated in BWRVIP-234-A: BWR

BWRVIP-315, Reactor Internals Aging Management Evaluation for Extended Operations (Continued)	
Action Item Description	**Browns Ferry Response**
BWRVIP-315 Applicant Action Item 4 (continued)	Vessel and Internals Project, Thermal Aging and Neutron Embrittlement Evaluation of Cast Austenitic Stainless Steels for BWR Internals. The BWRVIP-234-A evaluation determined that no supplemental (augmented) inspections, beyond those recommendations within the current BWRVIP reports were needed for these components to manage the aging effect of loss of fracture toughness due to thermal aging embrittlement and neutron irradiation embrittlement. The NRC staff in its final safety evaluation for BWRVIP-234-A accepted this recommendation, as adequately managing loss of fracture toughness due to thermal embrittlement and irradiation embrittlement and any possible combined effects of the two, for components that do not exceed 6 x10^{20} n/cm^2. For BFN Units 1, 2 and 3, all the Jet Pump components and repair components on all three BFN units are projected to have peak neutron fluence values at the end of the subsequent period of extended operation that do not exceed 6 x10^{20} n/cm^2 (E>1 MeV). Therefore, supplemental inspections or enhancements to the existing BWRVIP guidance are not necessary for the jet pump assemblies (transition piece including elbow, inlet mixer, and diffuser collar) and jet pump restrainer brackets. The neutron fluence analysis discussed in Section 4.2.1.2 also documents the fact that all of the Jet Pump components and repair components on all three BFN units are projected to have peak neutron fluence values at the end of the subsequent period of extended operation that do not exceed the neutron fluence thresholds for irradiation enhanced stress relaxation to be incorporated in BWRVIP-41-R4-A in newly added Section 3.2.7.

Appendix D - Technical Specifications

10 CFR 54.22 requires that an application for license renewal include any Technical Specification (TS) changes or additions necessary to manage the effects of aging during the period of extended operation.

In accordance with NUREG-2192, Section 4.2.2.1.4, for plants that have the Reactor Vessel Pressure-Temperature (P-T) limits located in the limiting conditions for operation (LCOs) of the TS, updated P-T limits for the subsequent period of extended operation need not be submitted as part of the Subsequent License Renewal Application (SLRA) since the P-T limits need to be updated through the 10 CFR 50.90 licensing process. However, the updated P-T limits for the subsequent period of operation must be established and completed using the applicable TS change process for updating the P-T limit curves prior to the plant's entry into the subsequent period of extended operation. For BFN, the P-T Limits are located in TS LCOs. Therefore, updated P-T Limits for the subsequent period of extended operation will be established and completed, using the 10 CFR 50.90 process, prior to the associated unit's entry into the subsequent period of extended operation. See Section 4.2.4 for additional information.

No other TS changes or additions were identified as necessary to manage the effects of aging during the subsequent period of extended operation. As such, no TS changes or additions are included with this SLRA.

~~Withhold from Public Disclosure Under 10 CFR 2.390~~

ENCLOSURE 3

Browns Ferry Nuclear Plant Subsequent License Renewal Application
Sections 4, Time-Limited Aging Analyses

(proprietary version)

ENCLOSURE 4

Affidavits

EPRI Affidavit for Proprietary Information contained in Sections 4.2.2, 4.2.5, and 4.2.6

GEH Affidavit for Proprietary Information contained in Sections 4.2.7, 4.2.13, and 4.3.3

AFFIDAVIT

Subject: Request for Withholding of the Following Proprietary Information Included In:

Browns Ferry Nuclear Plant Units 1, 2, and 3 -
Application for Subsequent Renewed Operating Licenses
Renewed Facility Operating License Nos. DPR-33, DPR-52, and DPR-68
NRC Docket Nos. 50-259, 50-260, and 50-296

I, Steve Swilley, being duly sworn, depose and state as follows:

I am the Vice President and Deputy Chief Nuclear Officer at Electric Power Research Institute, Inc., whose principal office is located at 3420 Hillview Avenue, Palo Alto, California ("EPRI"), and I have been specifically delegated responsibility for the above-listed Report which contains EPRI Proprietary Information that is sought under this Affidavit to be withheld "Proprietary Information". I am authorized to apply to the U.S. Nuclear Regulatory Commission ("NRC") for the withholding of the Proprietary Information on behalf of EPRI.

EPRI Proprietary Information is identified in the above referenced report with text inside double brackets.

{{This sentence is an example**}}**

EPRI requests that the Proprietary Information be withheld from the public on the following bases:

Withholding Based Upon Privileged and Confidential Trade Secrets or Commercial or Financial Information (see e.g. 10 C.F.R. §2.390(a)(4)):

a. The Proprietary Information is owned by EPRI and has been held in confidence by EPRI. All entities accepting copies of the Proprietary Information do so subject to written agreements imposing an obligation upon the recipient to maintain the confidentiality of the Proprietary Information. The Proprietary Information is disclosed only to parties who agree, in writing, to preserve the confidentiality thereof.

b. EPRI considers the Proprietary Information contained therein to constitute trade secrets of EPRI. As such, EPRI holds the information in confidence, and disclosure thereof is strictly limited to individuals and entities who have agreed, in writing, to maintain the confidentiality of the Information. EPRI made a substantial economic investment to develop the Proprietary Information, and, by prohibiting public disclosure, EPRI derives an economic benefit in the form of licensing royalties and other additional fees from the confidential nature of the Proprietary Information. If the Proprietary Information were publicly available to consultants and/or other businesses providing services in the electric and/or nuclear power industry, they would be able to use the Proprietary Information for their own commercial benefit and profit and without expending substantial economic resources required of EPRI to develop the Proprietary Information.

c. EPRI's classification of the Proprietary Information as trade secrets is justified by the Uniform Trade Secrets Act, which California adopted in 1984 and a version of which has been adopted by over forty states. The California Uniform Trade Secrets Act, California Civil Code §§3426 – 3426.11, defines a "trade secret" as follows:

"Trade secret' means information, including a formula, pattern, compilation, program device, method, technique, or process, that:

(1) Derives independent economic value, actual or potential, from not being generally known to the public or to other persons who can obtain economic value from its disclosure or use; and

2) Is the subject of efforts that are reasonable under the circumstances to maintain its secrecy."

d. The Proprietary Information contained therein are not generally known or available to the public. EPRI developed the Information only after making a determination that the Proprietary Information was not available from public sources. EPRI made a substantial investment of both money and employee hours in the development of the Proprietary Information. EPRI was required to devote these resources and effort to derive the Proprietary Information. As a result of such effort and cost, both in terms of dollars spent and dedicated employee time, the Proprietary Information is highly valuable to EPRI.

e. A public disclosure of the Proprietary Information would be highly likely to cause substantial harm to EPRI's competitive position and the ability of EPRI to license the Proprietary Information both domestically and internationally. The Proprietary Information and Report can only be acquired and/or duplicated by others using an equivalent investment of time and effort.

I have read the foregoing, and the matters stated herein are true and correct to the best of my knowledge, information, and belief. I make this affidavit under penalty of perjury under the laws of the United States of America and the laws of the State of North Carolina.

Executed at 1300 W WT Harris Blvd, Charlotte, NC being the premises and place of business of Electric Power Research Institute, Inc.

Date: 10/31/23

Steve Swilley

(State of North Carolina)
(County of Mecklenburg)

Subscribed and sworn to (or affirmed) before me on this 31st day of October, 2023 by Steve Swilley, proved to me on the basis of satisfactory evidence to be the person who appeared before me.

Signature Deborah H. Rouse (Seal)

My Commission Expires 2nd day of April, 2026

DEBORAH H. ROUSE
NOTARY PUBLIC
CABARRUS
COUNTY
NORTH CAROLINA

GE-Hitachi Nuclear Energy Americas, LLC

AFFIDAVIT

I, Kent Halac, state as follows:

(1) I am the Senior Engineer, GE-Hitachi Nuclear Energy Americas, LLC ("GEH"), and have been delegated the function of reviewing the information described in paragraph (2) which is sought to be withheld, and have been authorized to apply for its withholding.

(2) The information sought to be withheld is contained in the letter from K. Hulvey (TVA) to the Nuclear Regulatory Commission, CNL-24-001, "Browns Ferry Nuclear Plant Units 1, 2, and 3 – Application for Subsequent Renewed Operating Licenses." GEH proprietary information in CNL-24-001 is identified by bold font inside double curly brackets. **{{This sentence is an example}}**. In each case, Paragraph (3) of this affidavit provides the basis for the proprietary determination.

(3) In making this application for withholding of proprietary information of which it is the owner or licensee, GEH relies upon the exemption from disclosure set forth in the *Freedom of Information Act* ("FOIA"), 5 U.S.C. §552(b)(4), and the *Trade Secrets Act*, 18 U.S.C. §1905, and NRC regulations 10 CFR 9.17(a)(4), and 2.390(a)(4) for trade secrets (Exemption 4). The material for which exemption from disclosure is here sought also qualifies under the narrower definition of trade secret, within the meanings assigned to those terms for purposes of FOIA Exemption 4 in, respectively, Critical Mass Energy Project v. Nuclear Regulatory Commission, 975 F.2d 871 (D.C. Cir. 1992), and Public Citizen Health Research Group v. FDA, 704 F.2d 1280 (D.C. Cir. 1983).

(4) The information sought to be withheld is considered to be proprietary for the reasons set forth in paragraphs (4)a and (4)b. Some examples of categories of information that fit into the definition of proprietary information are:

a. Information that discloses a process, method, or apparatus, including supporting data and analyses, where prevention of its use by GEH's competitors without a license from GEH constitutes a competitive economic advantage over other companies;

b. Information that, if used by a competitor, would reduce its expenditure of resources or improve its competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing of a similar product;

c. Information that reveals aspects of past, present, or future GEH customer-funded development plans and programs, resulting in potential products to GEH;

d. Information that discloses trade secret or potentially patentable subject matter for which it may be desirable to obtain patent protection.

(5) To address 10 CFR 2.390(b)(4), the information sought to be withheld is being submitted to NRC in confidence. The information is of a sort customarily held in confidence by GEH and is in fact so held. The information sought to be withheld has, to the best of my knowledge and belief, consistently been held in confidence by GEH, not been disclosed publicly, and not been made available in public sources. All disclosures to third parties, including any required transmittals to the NRC, have been made, or must be made, pursuant to regulatory provisions for proprietary or confidentiality agreements or both that provide for maintaining the information in confidence. The initial designation of this information as proprietary information, and the subsequent steps taken to prevent its unauthorized disclosure, are as set forth in the following paragraphs (6) and (7).

(6) Initial approval of proprietary treatment of a document is made by the manager of the originating component, who is the person most likely to be acquainted with the value and sensitivity of the information in relation to industry knowledge, or who is the person most likely to be subject to the terms under which it was licensed to GEH.

(7) The procedure for approval of external release of such a document typically requires review by the staff manager, project manager, principal scientist, or other equivalent authority for technical content, competitive effect, and determination of the accuracy of the proprietary designation. Disclosures outside GEH are limited to regulatory bodies, customers, and potential customers, and their agents, suppliers, and licensees, and others with a legitimate need for the information, and then only in accordance with appropriate regulatory provisions or proprietary and/or confidentiality agreements.

(8) The information identified in paragraph (2) is classified as proprietary because it contains the detailed GEH methodology for fuel analyses for the GEH Boiling Water Reactor (BWR). These methods, techniques, and data along with their application to the design, modification, and analyses associated with the fuel analyses were achieved at a significant cost to GEH.

The development of the evaluation processes along with the interpretation and application of the analytical results is derived from the extensive experience databases that constitute a major GEH asset.

(9) Public disclosure of the information sought to be withheld is likely to cause substantial harm to GEH's competitive position and foreclose or reduce the availability of profit-making opportunities. The information is part of GEH's comprehensive BWR safety and technology base, and its commercial value extends beyond the original development cost. The value of the technology base goes beyond the extensive physical database and analytical methodology and includes development of the expertise to determine and apply the appropriate evaluation process. In addition, the technology base includes the value derived from providing analyses done with NRC-approved methods.

The research, development, engineering, analytical and NRC review costs comprise a substantial investment of time and money by GEH. The precise value of the expertise to devise an evaluation process and apply the correct analytical methodology is difficult to quantify, but it clearly is substantial. GEH's competitive advantage will be lost if its competitors are able to use the results of the GEH experience to normalize or verify their own process or if they are able to claim an equivalent understanding by demonstrating that they can arrive at the same or similar conclusions.

The value of this information to GEH would be lost if the information were disclosed to the public. Making such information available to competitors without there having been required to undertake a similar expenditure of resources would unfairly provide competitors with a windfall and deprive GEH of the opportunity to exercise its competitive advantage to seek an adequate return on its large investment in developing and obtaining these very valuable analytical tools.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on this 30th day of November 2023.

Kent Halac
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