Enclosure 2

SLRA MARK-UPS
CHANGE NOTICE 2

Virginia Electric and Power Company
(Dominion Energy Virginia)
Surry Power Station Units 1 and 2

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Section 2.3.3.34

Provide clarification in the system evaluation boundary that the diesel fire pump engine components are within the engine skid active assembly.

Section 2.3.3.34, Fire Protection, page 2-130 is supplemented as follows.

2.3.3.34 Fire Protection

System Evaluation Boundary

The evaluation boundary for the fire protection system components subject to aging management review includes the fire water system storage tanks, pumps, yard piping, distribution piping and components associated with all sprinkler, spray and hose station suppression features within the protected area, as well as suppression piping to and within the Radwaste Facility and Station Blackout Building outside the protected area. Additional fire water piping outside the protected area connecting to the Radwaste Facility and Station Blackout Building supply branches is within-scope up to the next isolation valves. All of the carbon dioxide suppression systems, along with the halon suppression systems in the emergency switchgear and relay rooms are subject to aging management review. The Security Building sub-floor halon system and the halon systems in the Training Building are not within the scope of subsequent license renewal. The halon systems are not depicted on subsequent license renewal drawings. Engine-driven fire pump support components within the engine skid boundaries are part of the active assembly, not subject to aging management review.

The foundations for the fire protection and domestic water storage tanks are evaluated in the structural section of the subsequent license renewal application. Structural fire barriers such as fire doors, fire-retardant coatings, or fire seals are evaluated in the structural section.

Section 2.4.1.1

Provide clarification in the system evaluation for seals and gaskets in the Containment System Evaluation Boundary.

Section 2.4.1.1, Containment, page 2-253 is supplemented as follows.

2.4.1.1 Containment

System Evaluation Boundary

The evaluation boundary for the containment structural members subject to aging management review includes structural members of the Containment, including basemat, drainage sump, internal structural members, waterproof membrane, and penetrations (personnel and emergency airlocks and equipment hatch, piping penetrations, electrical penetrations, ventilation dome opening with hatch cover, and heating and ventilation penetration). The refueling pool liner, reactor cavity liner, fuel transfer tube enclosure protection shield, and the reactor cavity seal ring are also included in the containment evaluation boundary.

For mechanical penetrations, flued heads and isolation valves are evaluated with the host system. Electrical penetration assemblies are within the scope of the EQ program. The portions of the electrical penetrations that form part of the containment pressure boundary are included within the containment evaluation boundary. The fuel transfer tube assembly and blind flange are evaluated for aging management with the fuel handling system. Fuel transfer tube supports are evaluated for aging management with the Component Supports. The sump screen assembly installed to prevent debris from entering the containment sump is evaluated for aging management with the recirculation spray system.

The gaskets and seals identified as O-rings ~~of~~ include seals and gaskets for the equipment hatch and personnel hatch doors, penetration flanges, fuel transfer blank flange, and other elastomer materials that provide leak-tight conditions inside Containment.

Table 2.4.1-1

Remove structural member of caulking and sealants since SPS does not have a moisture barrier between the Containment liner-concrete interface.

Table 2.4.1-1, Containment, page 2-305 is supplemented as follows.

Table 2.4.1-1 Containment

Structural Member	Intended Function(s)
~~Caulking and sealants~~	~~Enclosure Protection, Pressure Boundary~~

Table 2.4.1-37

This table is updated to clarify the flood barrier as applicable intended function for penetration seals and fire barrier seals.

Table 2.4.1-37, Miscellaneous Structural Commodities, page 2-342 is supplemented as follows.

Table 2.4.1-37 Miscellaneous Structural Commodities

Component Type	Intended Function(s)
Fire barrier seals	Fire Barrier, Flood Barrier
Penetration seals	Enclosure Protection, Flood Barrier Pressure Boundary

Table 3.0-1

Revise definition for closed-cycle cooling water to clarify use of treated water for erosion.

Table 3.0-1, Mechanical System Service Environments, page 3-6 is supplemented as follows.

Table 3.0-1 Mechanical System Service Environments

SPS AMR Environment	Definition	NUREG-2191 Environment(s) Used for AMR Comparison (1)
Closed-cycle cooling water	Treated water subject to the Closed Treated Water Systems chemistry program. Closed-cycle cooling water describes the environment in treated closed cooling and heating systems. Closed-cycle cooling water is aligned to NUREG-2191 items for treated water to address erosion of throttle valves in the bearing cooling system.	Closed-cycle cooling water, Treated water

3.1.2.1.1

Add cast austenitic stainless steel to the list of materials for the reactor vessel.

Section 3.1.2.1.1, Reactor Vessel, page 3-12 is supplemented as follows.

3.1.2.1.1 Reactor Vessel

Materials
The materials of construction for the reactor vessel subcomponents are:

- Cast austenitic stainless steel
- High-strength steel
- Nickel alloy
- Stainless steel
- Steel
- Steel with stainless steel cladding

3.1.2.1.3

Add reduction of heat transfer to the aging effects requiring management from identified heat exchanger components that were previously missing the function.

Section 3.1.2.1.3, Reactor Coolant, page 3-16 is supplemented as follows.

3.1.2.1.3 Reactor Coolant

Aging Effects Requiring Management

The following aging effects, associated with the reactor coolant system, require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of coating or lining integrity
- Loss of fracture toughness
- Loss of material
- Loss of preload
- Reduction of heat transfer
- Reduced thermal insulation resistance

Aging Management Programs

The following aging management programs manage the aging effects for the reactor coolant system component types:

- ASME Code Class 1 Small-Bore Piping (B2.1.22)
- ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)
- Bolting Integrity (B2.1.9)
- Boric Acid Corrosion (B2.1.4)
- Closed Treated Water Systems (B2.1.12)
- External Surfaces Monitoring of Mechanical Components (B2.1.23)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)
- Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)
- Lubricating Oil Analysis (B2.1.26)

- One-Time Inspection (B2.1.20)
- Selective Leaching (B2.1.21)
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B2.1.6)
- Water Chemistry (B2.1.2)

Table 3.1.1

[3.1.1-127] is updated to reflect updated AMR usage.

Table 3.1.1, Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report, page 3-77 is supplemented as follows.

Table 3.1.1 Summary of Aging Management Programs for Reactor Vessel, Internals, and Reactor Coolant System Evaluated in Chapter IV of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.1.1-127	Steel (with stainless steel or nickel alloy cladding) steam generator heads and tubesheets exposed to reactor coolant	Loss of material due to boric acid corrosion	AMP XI.M2, Water Chemistry, and AMP XI.M19, Steam Generators	No	Consistent with NUREG-2191 with exceptions~~, and with a different program for some components~~. Exceptions apply to the NUREG-2191 recommendations for Water Chemistry (B2.1.2) program implementation. ~~The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program will manage loss of material of the steel with stainless steel cladding steam generator primary inlet and outlet nozzles exposed to reactor coolant.~~

Table 3.1.2-1

Add AMR rows to address management of cast austenitic stainless steel control rod drive mechanism latch housings.

Table 3.1.2-1, Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation, page 3-82 is supplemented as follows.

Table 3.1.2-1 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Vessel - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Control rod drive mechanism (latch housing)	PB	Cast austenitic stainless steel	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	V.A.EP-103c	3.2.1-007	C
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	IV.C2.R-452b	3.1.1-136	C
			(I) Reactor coolant	Cracking	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)	IV.A2.RP-55	3.1.1-047	A
					Water Chemistry (B2.1.2)	IV.A2.RP-55	3.1.1-047	B
				Cumulative fatigue damage	TLAA	IV.A2.R-219	3.1.1-010	A
				Loss of material	Water Chemistry (B2.1.2)	IV.A2.RP-28	3.1.1-088	B
				Loss of fracture toughness	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) (B2.1.6)	IV.A2.R-77	3.1.1-050	A

Table 3.1.2-3

Add AMR rows to manage reduction of heat transfer on applicable heat exchangers.

Table 3.1.2-3, Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation, page 3-95 is supplemented as follows.

Table 3.1.2-3 Reactor Vessel, Internals, and Reactor Coolant System - Reactor Coolant - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (reactor coolant pump motor stator cooler – fin and tube)	HT;PB	Copper alloy	(E) Air – indoor uncontrolled	~~None~~ Reduction of heat transfer	~~None~~ Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	~~IV.E.R-453~~ VII.F3.A-419	~~3.1.1-137~~ 3.3.1-096a	~~C~~ A
			(I) Closed-cycle cooling water	Reduction of heat transfer	Closed Treated Water Systems (B2.1.12)	VII.C2.AP-205	3.3.1-050	A

Table 3.1.2-4

Correction of AMR rows for channel head (and cladding) and primary inlet nozzle and outer nozzle (and cladding).

Table 3.1.2-4, Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator - Aging Management Evaluation, pages 3-108, 3-110 and 3-114 are supplemented as follows.

Table 3.1.2-4 Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Channel head (and cladding)	PB	Steel with stainless steel cladding	(I) Reactor coolant	~~Cracking~~	~~ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)~~	~~IV.D1.RP-232~~	~~3.1.1-033~~	~~C~~
					~~Water Chemistry (B2.1.2)~~	~~IV.D1.RP-232~~	~~3.1.1-033~~	~~D~~
Primary inlet nozzle and outlet nozzle (and cladding)	PB	Steel with stainless steel cladding	(I) Reactor coolant	~~Loss of material~~	~~ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1)~~	~~IV.D1.R-436~~	~~3.1.1-127~~	~~E, 2~~
					~~Water Chemistry (B2.1.2)~~	~~IV.D1.R-436~~	~~3.1.1-127~~	~~B~~
				Loss of material	Water Chemistry (B2.1.2)	IV.C2.RP-23	3.1.1-088	A

Table 3.1.2-4 Plant-Specific Note:

2. ~~The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B2.1.1) program is used to manage loss of material for the primary inlet and outlet nozzles exposed to reactor coolant.~~ Not used.

Section 3.2.2.2.9

Correction in FER 3.2.2.2.9.

Section 3.2.2.2.9, Loss of Material Due to General, Crevice or Pitting Corrosion and Cracking Due to Stress Corrosion Cracking, pages 3-138 and 3-139 are supplemented as follows.

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.

Loss of material due to crevice or pitting corrosion, and cracking due to SCC can occur in stainless steel components exposed to concrete in the Engineered Safety Features at SPS.

[3.2.1-055] – SPS has no in-scope steel piping, piping components exposed to concrete in the Engineered Safety Features systems.

[3.2.1-091] – The concrete exposed stainless steel piping aligned to this item is embedded within interior concrete at the containment sump and is not potentially exposed to groundwater. There are no aging effects identified that require aging management.

Loss of material and cracking can occur for stainless steel piping components with an external environment of concrete that are potentially exposed to groundwater. Embedded piping that exits concrete into soil is potentially exposed to groundwater. Loss of material and cracking for stainless steel components with an external environment of concrete that exit the concrete into soil is managed by the Buried and Underground Piping and Tanks (B2.1.27) program as identified in items [3.2.1-053] and ~~[3.3.1-078]~~ [3.2.1-078].

Table 3.2.2-2

Addition of a clarifying note for the recirculation spray containment sump.

Table 3.2.2-2, Auxiliary Systems - Recirculation Spray - Aging Management Evaluation, pages 3-177 and 3-179 is supplemented as follows.

Table 3.2.2-2 Engineering Safety Features Systems - Recirculation Spray - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Stainless Steel	(E) Concrete	None	None	V.F.EP-20	3.2.1-091	A, 5

Table 3.2.2-2 Plant-Specific Note:

5. Suction piping embedded in concrete from the containment sump is not exposed to groundwater, and has no aging effects requiring management.

Section 3.3.2.1.20

This section is updated to include aluminum as an applicable material for the drains aerated system.

Section 3.3.2.1.20, Drains Aerated, page 3-227 is supplemented as follows.

3.3.2.1.20 Drains Aerated

Materials

The materials of construction for the drains aerated system component types are:

- Aluminum
- Elastomer
- Glass
- Gray cast iron
- Stainless Steel
- Steel

Section 3.3.2.2.8

Address the aging management of aluminum components in FER 3.3.2.2.8 for [3.3.1-189].

Section 3.3.2.2.8, Cracking Due to Stress Corrosion Cracking in Aluminum Alloys, pages 3-278, 3-279, 3-280, and 3-281 are supplemented as follows.

3.3.2.2.8 Cracking Due to Stress Corrosion Cracking in Aluminum Alloys

SCC is a form of environmentally assisted cracking which is known to occur in high and moderate strength aluminum alloys. The three conditions necessary for SCC to occur in a component are a sustained tensile stress, aggressive environment, and material with a susceptible microstructure. Cracking due to SCC can be mitigated by eliminating one of the three necessary conditions. For the purposes of SLR, acceptance criteria for this further evaluation is being provided for demonstrating that the specific material is not susceptible to SCC or an aggressive environment is not present. Cracking due to SCC is an aging effect requiring management unless it is demonstrated by the applicant that one of the two necessary conditions discussed below is absent. Susceptible Material: If the material is not susceptible to SCC then cracking is not an aging effect requiring management. The microstructure of an aluminum alloy, of which alloy composition is only one factor, is what determines if the alloy is susceptible to SCC. Therefore, determining susceptibility based on alloy composition alone is not adequate to conclude whether a particular material is susceptible to SCC. The temper, condition, and product form of the alloy is considered when assessing if a material is susceptible to SCC. Aluminum alloys that are susceptible to SCC include:

- *2xxx series alloys in the F, W, Ox, T3x, T4x, or T6x temper*
- *5xxx series alloys with a magnesium content of 3.5 weight percent or greater*
- *6xxx series alloys in the F temper*
- *7xxx series alloys in the F, T5x, or T6x temper*
- *2xx.x and 7xx.x series alloys*
- *3xx.x series alloys that contain copper*
- *5xx.x series alloys with a magnesium content of greater than 8 weight percent*

The material is evaluated to verify that it is not susceptible to SCC and that the basis used to make the determination is technically substantiated. Tempers have been specifically developed to improve the SCC resistance for some aluminum alloys. Aluminum alloy and temper combination which are not susceptible to SCC when used in piping, piping component, and tank applications include 1xxx series, 3xxx series, 6061-T6x, and 5454-x. If it is determined that a material is not susceptible to SCC, the SLRA provides the components/locations where it is used, alloy composition, temper or condition, product form, and for tempers not addressed above, the basis used to determine the alloy is not susceptible and technical information substantiating the basis. Aggressive Environment: If the environment to which an aluminum alloy is exposed is not aggressive, such as dry gas or treated water, then cracking due to SCC will not occur and it is not an aging effect requiring management. Aggressive environments that are known to result in cracking due to SCC of susceptible aluminum alloys are aqueous *solutions, air, condensation, and underground locations that contain halides (e.g., chloride). Halide concentrations should be considered high enough to facilitate SCC of aluminum alloys in uncontrolled or untreated aqueous solutions and air, such as raw water, waste water, condensation, underground locations, and outdoor air, unless demonstrated otherwise.*

Halides could be present on the surface of the aluminum material if the component is encapsulated in a material such as insulation or concrete. In a controlled or uncontrolled indoor air, condensation, or underground environment, sufficient halide concentrations to cause SCC could be present due to secondary sources such as leakage from nearby components (e.g., leakage from insulated flanged connections or valve packing). If an aluminum component is exposed to a halide free indoor air environment, not encapsulated in materials containing halides, and the exposure to secondary sources of moisture or halides is precluded, cracking due to SCC is not expected to occur. The plant-specific configuration can be used to demonstrate that exposure to halides will not occur. If it is determined that SCC will not occur because the environment is not aggressive, the SLRA provides the components and locations exposed to the environment, a description of the environment, basis used to determine the environment is not aggressive, and technical information substantiating the basis. The GALL SLR Report AMP XI.M32, "One-Time Inspection," and a review of plant specific OE describe an acceptable means to confirm the absence of moisture or halides within the proximity of the aluminum component.

If the environment potentially contains halides, GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," describes an acceptable program to manage cracking due to SCC of aluminum tanks. GALL-SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," describes an acceptable program to manage cracking due to SCC of aluminum piping and piping components. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage cracking due to SCC of aluminum piping and tanks which are buried or underground. GALL SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" describes an acceptable program to manage cracking due to SCC of aluminum components that are not included in other AMPs.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent SCC. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and air that contain halides. If a barrier coating is credited for isolating an aluminum alloy from a potentially aggressive environment, then the barrier coating is evaluated to verify that it is impervious to the plant-specific environment. GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks," describes an acceptable program to manage the integrity of a barrier coating for internal or external coatings.

Cracking due to stress corrosion cracking is an aging effect requiring management for aluminum alloy components exposed to air or condensation in the Auxiliary Systems for SPS.

A review of SPS operating experience did not identify a history of cracking of aluminum alloy components. However, operating experience as discussed in Sections 3.3.2.2.3

and 3.3.2.2.4 confirmed that the external surfaces of some stainless steel components have experienced aging that was supported by the presence of halides.
Stress corrosion cracking of susceptible aluminum alloys in air is supported by the presence of the same contaminants that support loss of material and cracking in stainless steel. Since these aging effects have been identified in some stainless steel components, the potential for chloride contamination of aluminum alloy surfaces could not be discounted, and because rainwater leakage or leakage from bolted connections may provide both a source of water and the opportunity for a concentration of contaminants, the potential for cracking due to stress corrosion cracking of aluminum alloys in air or condensation environments is assessed to exist at SPS in aging evaluations performed for subsequent license renewal.

[3.3.1-186] – SPS has no in-scope aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation, soil, concrete, raw water or waste water in the Auxiliary Systems.

[3.3.1-189] – Cracking of aluminum piping, piping components, tanks exposed to air, condensation, raw water, raw water (potable), waste water is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program or the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program. The internal surfaces of some components in the emergency diesel generator <u>and drains aerated</u> system<u>s</u> are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition.

[3.3.1-192] – SPS has no in-scope aluminum underground piping, piping components, or tanks in the Auxiliary Systems.

[3.3.1-233] – SPS has no in-scope insulated aluminum piping, piping components, tanks exposed to an external environment of air-outdoor or condensation in the Auxiliary Systems. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable.

[3.3.1-254] – Cracking of aluminum heat exchanger components exposed to air is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, or by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program.

Section 3.3.2.2.10

Address the addition of aluminum components in FER 3.3.2.2.10 for [3.3.1-247].

Section 3.3.2.2.10, Loss of Material Due to Pitting and Crevice Corrosion in Aluminum Alloys, page 3-285 is supplemented as follows.

3.3.2.2.10 Loss of Material Due to Pitting and Crevice Corrosion in Aluminum Alloys

Loss of material due to pitting and crevice corrosion could occur in aluminum piping, piping components, and tanks exposed to an air, condensation, underground, raw water, or waste water environment for a sufficient duration of time. Environments that can result in pitting and/or crevice corrosion of aluminum alloys are those that contain halides (e.g., chloride) in the presence of moisture. The moisture level and halide concentration in atmospheric and uncontrolled air are greatly dependent on geographical location and site-specific conditions. Moisture level and halide concentration should generally be considered high enough to facilitate pitting and/or crevice corrosion of aluminum alloys in atmospheric and uncontrolled air, unless demonstrated otherwise. The periodic introduction of moisture or halides into an environment from secondary sources should also be considered. Leakage of fluids from mechanical connections (e.g., insulated bolted flanges and valve packing); onto a component in indoor controlled air is an example of a secondary source that should be considered. Halide concentrations should generally be considered high enough to facilitate loss of material of aluminum alloys in untreated aqueous solutions, unless demonstrated otherwise. Plant-specific OE and the condition of aluminum alloy components are evaluated to determine if prolonged exposure to the plant-specific air, condensation, underground, or water environments has resulted in pitting or crevice corrosion. Loss of material due to pitting and crevice corrosion is not an aging effect requiring management for aluminum alloys if: (a) plant-specific OE does not reveal a history of loss of material due to pitting or crevice corrosion and (b) a one-time inspection demonstrates that the aging effect is not occurring or is occurring so slowly that it will not affect the intended function of the components. The applicant documents the results of the plant specific OE review in the SLRA.

In the environment of air-indoor controlled, pitting and crevice corrosion is only expected to occur as the result of a source of moisture and halides. Alloy susceptibility may be considered when reviewing OE and interpreting inspection results. Inspections focus on the most susceptible alloys and locations.

The GALL-SLR Report recommends the further evaluation of aluminum piping, piping components, and tanks exposed to an air, condensation, or underground environment to determine whether an AMP is needed to manage the aging effect of loss of material due to pitting and crevice corrosion. GALL-SLR Report AMP XI.M32, "One-Time

Inspection," describes an acceptable program to demonstrate that the aging effect of loss of material due to pitting and crevice corrosion is not occurring at a rate that will affect the intended function of the components. If loss of material due to pitting or crevice corrosion has occurred and is sufficient to potentially affect the intended function of an SSC, the following AMPs describe acceptable programs to manage loss of material due to pitting and crevice corrosion: (i) GALL-SLR Report AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks," for tanks; (ii) GALL SLR Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," for external surfaces of piping and piping components; (iii) GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," for underground piping, piping components and tanks; and (iv) GALL-SLR Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" for internal surfaces of components that are not included in other AMPs. The timing of the one time or periodic inspections is consistent with that recommended in the AMP selected by the applicant during the development of the SLRA. For example, one time inspections would be conducted between the 50th and 60th year of operation, as recommended by the "detection of aging effects" program element in AMP XI.M32.

An alternative strategy to demonstrating that an aggressive environment is not present is to isolate the aluminum alloy from the environment using a barrier to prevent loss of material due to pitting and crevice corrosion. Acceptable barriers include tightly adhering coatings that have been demonstrated to be impermeable to aqueous solutions and atmospheric air that contain halides. If a barrier coating is credited for isolating an aluminum alloy from a potentially aggressive environment, then the barrier coating is evaluated to verify that it is impervious to the plant specific environment. The GALL-SLR Report AMP XI.M42, "Internal Coatings/Linings for In Scope Piping, Piping Components, Heat Exchangers, and Tanks," or equivalent program, describes an acceptable program to manage the integrity of a barrier coating.

Loss of material due to pitting and crevice corrosion is an aging effect requiring management for aluminum alloy components exposed to air and condensation in the Auxiliary Systems for SPS

A review of SPS operating experience did not identify a history of loss of material of in-scope aluminum alloy components. However, operating experience as discussed in Sections 3.3.2.2.3 and 3.4.2.2.4 confirmed that the external surfaces of some stainless steel components have experienced aging that was supported by the presence of halides.

Pitting and crevice corrosion of aluminum alloys in air is supported by the presence of the same contaminants that support loss of material and cracking in stainless steel. Since these aging effects have been identified in some stainless steel components, the potential for chloride contamination of aluminum alloy surfaces could not be discounted, and because rainwater leakage or leakage from bolted connections may provide both a source of water and the opportunity for a concentration of contaminants, the potential for loss of material due to pitting and crevice corrosion of aluminum alloys in air or condensation environments is assessed to exist at SPS in aging evaluations performed for subsequent license renewal.

[3.3.1-223] – SPS has no in-scope aluminum underground piping, piping components or tanks in the Auxiliary Systems.

[3.3.1-227] – SPS has no in-scope aluminum tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air or condensation in the Auxiliary Systems.

[3.3.1-234] – Loss of material of aluminum components exposed to air or condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program or the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program. The internal surfaces of some components in the emergency diesel generator system are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition.

[3.3.1-240] – ~~SPS has no in-scope aluminum heat exchanger components exposed to waste water in the Auxiliary Systems.~~ Loss of material of aluminum components exposed to waste water is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program. The internal surfaces of some components in the drains-aerated systems are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition.

[3.3.1-242] – Loss of material of aluminum heat exchanger components exposed to air is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, or by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program.

[3.3.1-245] - SPS has no in-scope insulated aluminum piping, piping components, or tanks exposed to an external environment of air-outdoor or condensation in the Auxiliary Systems. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable.

[3.3.1-247] – ~~SPS has no in-scope aluminum piping, piping components or tanks exposed to raw water or waste water in the Auxiliary Systems.~~ Loss of material of aluminum components exposed to waste water is addressed in item [3.3.1-240]. SPS does not have any in-scope aluminum components exposed to raw water in the Auxiliary Systems.

Table 3.3.1

[3.3.1-050] and [3.3.1-096a] are updated to clarify the addition of the reduction of heat transfer aging effect managed by these items in the reactor coolant system.

[3.3.1-070] is updated to clarify the programs used to manage applicable components in the security system.

[3.3.1-132] is updated to clarify cracking of fire protection sprinkler heads and cracking of valve bodies.

[3.3.1-189] is updated to clarify the addition of the aluminum containment sump pumps.

[3.3.1-240] is updated to clarify the addition of the aluminum containment sump pumps.

[3.3.1-247] is updated to clarify the addition of the aluminum containment sump pumps.

Table 3.3.1, Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report, pages 3-294, 3-297, 3-302, 3-309, 3-317, 3-327, and 3-329, are supplemented as follows. (See Next Page)

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-050	Stainless steel, copper alloy, steel heat exchanger tubes exposed to closed-cycle cooling water	Reduction of heat transfer due to fouling	AMP XI.M21A, Closed Treated Water Systems	No	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for Closed Treated Water Systems (B2.1.12) program implementation. In addition to Auxiliary Systems, components in Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) are aligned to this item.
3.3.1-070	Steel piping, piping components, tanks exposed to fuel oil	Loss of material due to general, pitting, crevice corrosion, MIC	AMP XI.M30, Fuel Oil Chemistry, and AMP XI.M32, One-Time Inspection, or AMP XI.M30, Fuel Oil Chemistry	No	Consistent with NUREG-2191 with exceptions. Loss of material of steel components exposed to fuel oil is managed by the Fuel Oil Chemistry (B2.1.18) program, or (for the security system), by the Fuel Oil Chemistry (B2.1.18) and One-Time Inspection (B2.1.20) programs. In addition to Auxiliary Systems, components in Steam and Power Conversion System (heating) are aligned to this item. For the heating system, loss of material of steel components exposed to fuel oil is managed by the Fuel Oil Chemistry (B2.1.18) program and the One-Time Inspection (B2.1.20) program. Exceptions apply to the NUREG-2191 recommendations for Fuel Oil Chemistry (B2.1.18) program implementation.
3.3.1-096a	Steel, aluminum, copper alloy, stainless steel, titanium heat exchanger tubes internal to components exposed to air, condensation (external)	Reduction of heat transfer due to fouling	AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	No	Consistent with NUREG-2191. In addition to Auxiliary Systems, components in the Reactor Vessel, Internals, and Reactor Coolant System (reactor coolant) and Engineered Safety Features (recirculation spray) are aligned to this item.

E3.3.1-132	Insulated steel, copper alloy (>15% Zn or >8% Al), piping, piping components, tanks, tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air, condensation	Loss of material due to general, pitting, crevice corrosion (steel only); cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	AMP XI.M36, External Surfaces Monitoring of Mechanical Components or AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Consistent with NUREG-2191 with a different program assigned for some components. ~~Loss of material of steel and copper alloy (>15% Zn or >8% Al) components and c~~Cracking of copper alloy (>15% Zn or >8% Al) fire protection sprinkler heads exposed to air-outdoor, is managed by the Fire Water System (B2.1.16) program. Loss of material of steel, and cracking of other copper alloy>15% Zn components exposed to air-outdoor or external condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program. Cracking of copper alloy (>15% Zn) exposed to an internal condensation environment is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable. Cracking of insulated copper alloy >15% Zn valve bodies exposed to air-indoor uncontrolled that are normally below 212°F are managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program. Aging of uninsulated copper alloy (>15% Zn) components exposed to air-indoor uncontrolled in the Auxiliary Systems is aligned to items 3.3.1-114, 3.3.1-130 and 3.3.1-131. Cracking of copper alloy (>15% Zn) in air is not expected in the absence of wetting and ammonia contaminants, which are not present in the air-indoor uncontrolled environment.

3.3.1-189	Aluminum piping, piping components, tanks exposed to air, condensation, raw water, raw water (potable), waste water	Cracking due to SCC	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.8)	Consistent with NUREG-2191. Cracking of aluminum piping, piping components, tanks exposed to ~~air or condensation~~ air, condensation or waste water is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program, or the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program. SPS has no in-scope aluminum piping, piping components or tanks exposed to raw water ~~or waste water~~ in the Auxiliary Systems. The internal surfaces of some components in the emergency diesel generator and drains-aerated systems are aligned to this item with management by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program, where their internal and external environments are such that the external surface condition is representative of the internal surface condition. See further evaluation in Section 3.3.2.2.8.
3.3.1-240	Aluminum heat exchanger components exposed to waste water	Loss of material due to pitting, crevice corrosion	AMP XI.M32, One-Time Inspection, AMP XI.M36, External Surfaces Monitoring of Mechanical Components, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.10)	~~Not applicable. SPS has no in-scope aluminum heat exchanger components exposed to waste water in the Auxiliary Systems. The associated NUREG 2191 aging items are not used. See further evaluation in Section 3.3.2.2.10.~~ Consistent with NUREG-2191. Loss of material for aluminum containment sump pumps exposed to waste water is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program. See further evaluation in Section 3.3.2.2.10.

3.3.1-247	Aluminum piping, piping components, tanks exposed to raw water, waste water	Loss of material due to pitting, crevice corrosion	AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, AMP XI.M32, One-Time Inspection, AMP XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, or AMP XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	Yes (SRP-SLR Section 3.3.2.2.10)	~~Not applicable. SPS has no in-scope aluminum piping, piping components or tanks exposed to raw water or waste water in the Auxiliary Systems. The associated NUREG-2191 aging items are not used. See further evaluation in Section 3.3.2.2.10.~~ Not applicable. Loss of material of aluminum components exposed to waste water is addressed in item [3.3.1-240]. SPS has no in-scope aluminum piping, piping components or tanks exposed to raw water in the Auxiliary Systems. See further evaluation in Section 3.3.2.2.10.

Table 3.3.2-1

Revise NUREG-2191 consistency notes for the ASME Section XI, Subsection IWE program from A to B.

Table 3.3.2-1, Auxiliary Systems - Fuel Handling - Aging Management Evaluation, pages 3-335 and 3-336 are supplemented as follows.

Table 3.3.2-1 Auxiliary Systems - Fuel Handling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Blind flange (fuel transfer tube)	PB	Stainless Steel	(E) Air – indoor uncontrolled	Cracking (CLB fatigue analysis does not exist)	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	~~A~~ B
				Cracking	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-38	3.5.1-010	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-38	3.5.1-010	B
Fuel transfer tube	PB	Stainless Steel	(E) Air – indoor uncontrolled	Cracking (CLB fatigue analysis does not exist)	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	~~A~~ B
				Cracking	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-38	3.5.1-010	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-38	3.5.1-010	B
Fuel transfer tube enclosure	PB	Stainless Steel	(E) Air – indoor uncontrolled	Cracking (CLB fatigue analysis does not exist)	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	~~A~~ B
				Cracking	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-38	3.5.1-010	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-38	3.5.1-010	B

Table 3.3.2-2

Addition of the cracking TLAA for the fuel pool cooling system.

Table 3.3.2-2, Auxiliary Systems - Fuel Pool Cooling - Aging Management Evaluation, pages 3-338 and 3-339 is supplemented as follows.

Table 3.3.2-2 Auxiliary Systems - Fuel Pool Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Stainless Steel	(I) Treated Borated Water	Cracking	TLAA	None	None	H, 1

Table 3.3.2-2 Plant-Specific Note:

1. Fatigue cracking of fuel pool cooling piping defects is a TLAA, evaluated in Section 4.7.5, Piping Subsurface Flaw Evaluations

Table 3.3.2-3

Clarification of what AMP manages stainless steel crane components.

Table 3.3.2-3, Auxiliary Systems - Cranes and Hoists - Aging Management Evaluation, pages 3-340 and 3-341 are supplemented as follows.

Table 3.3.2-3 Auxiliary Systems - Cranes and Hoists - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Stainless Steel	(E) Air – indoor uncontrolled	Loss of material; cracking	~~One-Time Inspection (B2.1.20)~~ Structures Monitoring (B2.1.34)	~~III.B5.T-37a~~ III.B5.T-37b	3.5.1-100	A
Crane rails and retaining clips, girders, beams, plates	SS	Stainless Steel	(E) Air – indoor uncontrolled	Loss of material; cracking	~~One-Time Inspection (B2.1.20)~~ Structures Monitoring (B2.1.34)	~~III.B5.T-37a~~ III.B5.T-37b	3.5.1-100	A
Lifting devices	SS	Stainless Steel	(E) Air – indoor uncontrolled	Loss of material; cracking	~~One-Time Inspection (B2.1.20)~~ Structures Monitoring (B2.1.34)	~~III.B5.T-37a~~ III.B5.T-37b	3.5.1-100	A

Table 3.3.2-4

Clarification of management of fiberglass components and titanium valve bodies in the service water system.

Table 3.3.2-4, Auxiliary Systems - Service Water - Aging Management Evaluation, page 3-334, 3-354, and 3-355 are supplemented as follows.

Table 3.3.2-4 Auxiliary Systems - Service Water - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	LB;PB	Fiberglass	(I) Raw water	~~Wall thinning~~	~~Flow-Accelerated Corrosion (B2.1.8)~~	~~None~~	~~None~~	~~H~~
				Cracking, blistering, loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	Vii.C1.A-460	3.3.1-175	A,2,3
Valve body	LB;PB	Titanium	(I) Air – indoor uncontrolled	None	None	VII.J.AP-160	3.3.1-122	A;9
			(I) Raw water	Cracking; flow blockage	~~Open-Cycle Cooling Water System (B2.1.11)~~	~~VII.C1.AP-161a~~	~~3.3.1-123~~	~~B~~

Table 3.3.2-4 Plant-Specific Notes:

9. Valve bodies are fabricated of Titanium (ASTM grade 4).

Table 3.3.2-6

Include AMR rows to clarify management of erosion on specific bearing cooling system valves used for throttling.

Table 3.3.2-6, Auxiliary Systems - Bearing Cooling - Aging Management Evaluation, pages 3-365 and 3-366 are supplemented as follows.

Table 3.3.2-6 Auxiliary Systems - Bearing Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Copper alloy	(I) Closed-cycle cooling water	Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.D1.S-408	3.4.1-060	A, 4
		Gray cast iron	(I) Closed-cycle cooling water	Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.D1.S-408	3.4.1-060	A, 4
		Stainless Steel	(I) Closed-cycle cooling water	Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.D1.S-408	3.4.1-060	A, 4
		Steel	(I) Closed-cycle cooling water	Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.D1.S-408	3.4.1-060	A, 4

Table 3.3.2-6 Plant-Specific Note:

4. Closed-cycle cooling water is aligned to NUREG-2191 items for treated water to address erosion of throttle valves in the bearing cooling system.

Table 3.3.2-8

Include AMR rows to clarify management of reduction of heat transfer on specific heat exchangers.

Table 3.3.2-8, Auxiliary Systems - Component Cooling - Aging Management Evaluation, page 3-373 is supplemented as follows.

Table 3.3.2-8 Auxiliary Systems - Component Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (containment penetration jacket)	HT;PB	Stainless steel	(E) Air – indoor uncontrolled	Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-716	3.3.1-151	A
Heat exchanger (shield penetration jacket)	HT;PB	Stainless steel	(E) Air – indoor uncontrolled	Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-716	3.3.1-151	A

Table 3.3.2-9

Include AMR row to clarify management of reduction of heat transfer on specific heat exchanger.

Table 3.3.2-9, Auxiliary Systems - Neutron Shield Tank Cooling - Aging Management Evaluation, page 3-380 is supplemented as follows.

Table 3.3.2-9 Auxiliary Systems - Neutron Shield Tank Cooling - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (shield wall panel)	HT;PB	Stainless steel	(E) Air – indoor uncontrolled	Reduction of heat transfer	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-716	3.3.1-151	A

Table 3.3.2-20

Correction of reactor containment sump pump material.

Table 3.3.2-20, Auxiliary Systems - Drains Aerated - Aging Management Evaluation, pages 3-442 and 3-444 are supplemented as follows.

Table 3.3.2-20 Auxiliary Systems - Drains Aerated - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Pump casing (reactor containment sump pump)	LB	~~Stainless steel~~	~~(E) Air – indoor uncontrolled~~	~~Cracking~~	~~External Surfaces Monitoring of Mechanical Components (B2.1.23)~~	~~VII.E1.AP-209b~~	~~3.3.1-004~~	~~A~~
				~~Loss of material~~	~~External Surfaces Monitoring of Mechanical Components (B2.1.23)~~	~~VII.E1.AP-221b~~	~~3.3.1-006~~	~~A~~
			~~(I) Waste water~~	~~Loss of material; flow blockage~~	~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)~~	~~VII.E5.AP-278~~	~~3.3.1-095~~	~~A, 1~~
		Aluminum	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5-A-451b	3.3.1-189	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5-A-763b	3.3.1-234	A
			(I) Waste water	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5-A-451b	3.3.1-189	A:2
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5-A-769b	3.3.1-240	C:2
			(E) Waste water	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5-A-451b	3.3.1-189	A
				Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.E5-A-769b	3.3.1-240	C

Table 3.3.2-20 Plant-Specific Notes:

2. Internal and external environments are such that the external surface condition is representative of the internal surface condition.

Table 3.3.2-28

Addition of external cracking for insulated valve bodies in domestic water hot water flowpaths.

Table 3.3.2-28, Auxiliary Systems - Water Treatment - Aging Management Evaluation, pages 3-480 and 3-482 is supplemented as follows.

Table 3.3.2-28 Auxiliary Systems - Water Treatment - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB	Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	Cracking	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-405e	3.3.1-132	A,2

Table 3.3.2-28 Plant-Specific Note:

2. Cracking is applicable for insulated valve bodies in domestic water hot water flowpaths.

Table 3.3.2-34

Addition of external cracking for sprinkler heads in the fire protection system and removal of a note that is no longer applicable.

Table 3.3.2-34, Auxiliary Systems - Fire Protection- Aging Management Evaluation, pages 3-510, 3-511 and 3-515 is supplemented as follows.

Table 3.3.2-34 Auxiliary Systems - Fire Protection - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	PB	Steel	(I) Raw Water	~~Cracking~~	~~TLAA~~	~~None~~	~~None~~	~~H, 6~~
Sprinkler head	SP	Copper alloy (>15% Zn)	(E) Air – outdoor	Cracking	Fire Water System (B2.1.26)	VII.I.A-405e	3.3.1-132	E, 6

Table 3.3.2-34 Plant-Specific Note:

4. The Fire Water System (B2.1.16) program is used ~~instead of the Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program~~ to manage loss of material and loss of coating integrity for internally coated carbon steel fire water storage tanks. ~~The Fire Water System (B2.1.16) program manages degraded internal coatings c~~Consistent with NUREG-2191 Table XI.M27-1 note 4, when degraded coatings are detected by internal coating inspections, acceptance criteria and corrective action recommendations are followed consistent with the Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28) program.

~~6. Fatigue cracking of fire protection piping defects is a TLAA, evaluated in Section 4.7.5, Piping Subsurface Flaw Evaluations~~

6. Cracking of copper alloy >15% Zn sprinkler heads exposed to air-outdoor will be managed by the Fire Water System (B.1.16) program.

Table 3.3.2-37

Include AMR row to clarify management of reduction of heat transfer on specific heat exchanger.

Revise the material name of the galvanized steel jacket water expansion tank, and assign the Closed Treated Water Systems program for more appropriate management of the metallic surface.

Table 3.3.2-37, Auxiliary Systems - Alternate AC - Aging Management Evaluation, pages 3-534, 3-537 and 3-541 are supplemented as follows.

Table 3.3.2-37 Auxiliary Systems - Alternate AC - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (cooling water and fuel oil radiators – tube)	HT;PB	Steel	(I) Fuel oil	Reduction of heat transfer	Fuel Oil Chemistry (B2.1.18)	N/A	N/A	H, 4
Tank (jacket water expansion)	PB	Steel ~~with internal coating~~	(E) Air – indoor uncontrolled	Loss of material	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-77	3.3.1-078	A;5
			(I) Closed-cycle cooling water	~~Loss of coating or lining integrity~~	~~Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)~~	~~VII.C2.A-416~~	~~3.3.1-138~~	A
				Loss of material	~~Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (B2.1.28)~~ Closed Treated Water Systems (B2.1.12) program	~~VII.C2.A-414~~ VII.H2.AP-202	~~3.3.1-139~~ 3.3.1-045	A B;5

Table 3.3.2-37 Plant-Specific Notes:

4. The Fuel Oil Chemistry (B2.1.18) program will manage reduction of heat transfer in fuel oil radiator tubes.
5. The jacket water expansion tank is made of galvanized steel, but is called "Steel" to provide appropriate management of the metallic surface.

Table 3.3.2-38

Clarify AMR row that manages steel exposed to fuel oil for piping, piping components and pump casing (fuel oil).

Table 3.3.2-38, Auxiliary Systems - Security - Aging Management Evaluation, page 3-545 is supplemented as follows.

Table 3.3.2-38 Auxiliary Systems - Security - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Piping, piping components	PB	Steel	(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
					One-Time Inspection (B2.1.20)	VII.H2.AP-105	3.3.1-070	A
Pump casing (fuel oil)	PB	Steel	(I) Fuel oil	Loss of material	Fuel Oil Chemistry (B2.1.18)	VII.H2.AP-105a	3.3.1-070	B
					One-Time Inspection (B2.1.20)	VII.H2.AP-105	3.3.1-070	A

Table 3.4.1

[3.4.1-060] is updated to manage erosion in the bearing cooling system.

Table 3.4.1, Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report, page 3-599 is supplemented as follows.

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion System Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-060	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. In addition to Steam and Power Conversion System, components in Auxiliary Systems (bearing cooling system) are aligned to this item.

Table 3.4.2-8

Addition of flow-accelerated corrosion as an aging effect requirement management for the first point feedwater heater channel.

Table 3.4.2-8, Steam and Power Conversion System - Feedwater - Aging Management Evaluation, page 3-647 is supplemented as follows.

Table 3.4.2-8 Steam and Power Conversion System - Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (first point feedwater heater – channel)	LB	Steel	(I) Treated water	Wall thinning	Flow-Accelerated Corrosion (B2.1.8)	VIII.D1.S-16	3.4.1-005	A

Section 3.5.2.1.1

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for Containment, and for clarification of management of stainless steel and aluminum in air, as shown below.

Section 3.5.2.1.1, Containment, page 3-683 is supplemented as follows.

3.5.2.1.1 Containment

Environment

The containment structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Air with borated water leakage
- Concrete
- Groundwater
- Soil
- Treated borated water
- Water – flowing
- ~~Water – standing~~

Aging Effects Requiring Management

The following aging effects, associated with the containment structural members, require management:

- Cracking
- Cracking and distortion
- Cumulative fatigue damage
- Increase in porosity and permeability
- Loss of bond
- Loss of coating or lining integrity
- Loss of leak tightness
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload

- Loss of sealing
- Loss of strength
- Reduction in concrete anchor capacity
- Reduction of foundation strength and cracking

Aging Management Programs

The following aging management programs manage the aging effects for the containment structural members:

- 10 CFR Part 50, Appendix J (B2.1.32)
- ASME Section XI, Subsection IWE (B2.1.29)
- ASME Section XI, Subsection IWL (B2.1.30)
- Boric Acid Corrosion (B2.1.4)
- Fire Protection (B2.1.15)
- Masonry Walls (B2.1.33)
- ~~One-Time Inspection (B2.1.20)~~
- Protective Coating Monitoring and Maintenance (B2.1.36)
- Structures Monitoring (B2.1.34)
- Water Chemistry (B2.1.2)

Section 3.5.2.1.2

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Auxiliary Building Structure as shown below.

Section 3.5.2.1.2, Auxiliary Building Structure, page 3-685 is supplemented as follows.

3.5.2.1.2 Auxiliary Building Structure

Aging Effects Requiring Management

The following aging effects, associated with the auxiliary building structure structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength
- Reduction of foundation strength and cracking

Section 3.5.2.1.5

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Fuel Building Structure as shown below.

Section 3.5.2.1.5, Fuel Building Structure, page 3-689 is supplemented as follows.

3.5.2.1.5 Fuel Building Structure

Aging Effects Requiring Management

The following aging effects, associated with the fuel building structure structural members, require management:

- Cracking
- Cracking and distortion
- Cumulative fatigue damage
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength
- Reduction of foundation strength and cracking

Section 3.5.2.1.9

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Black Battery Building as shown below.

Section 3.5.2.1.9, Black Battery Building, page 3-695 is supplemented as follows.

3.5.2.1.9 Black Battery Building

Environment

The black battery building structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the black battery building structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of preload
- Loss of strength

Section 3.5.2.1.10

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Central Alarm Station as shown below.

Section 3.5.2.1.10, Central Alarm Station, page 3-696 is supplemented as follows.

3.5.2.1.10 Central Alarm Station

Environment

The central alarm station structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the central alarm station structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of preload
- Loss of sealing
- Loss of strength

Section 3.5.2.1.11

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Condensate Polishing Building as shown below.

Section 3.5.2.1.11, Condensate Polishing Building, page 3-697 is supplemented as follows.

3.5.2.1.11 Condensate Polishing Building

Environment

The condensate polishing building structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the condensate polishing building structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of preload
- Loss of sealing
- Loss of strength

Section 3.5.2.1.12

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Laundry Facility as shown below.

Section 3.5.2.1.12, Laundry Facility, page 3-698 is supplemented as follows.

3.5.2.1.12 Laundry Facility

Environment

The laundry facility structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the laundry facility structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of sealing
- Loss of strength

Section 3.5.2.1.13

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Machine Shop as shown below.

Section 3.5.2.1.13, Machine Shop, page 3-699 is supplemented as follows.

3.5.2.1.13 Machine Shop

Environment

The machine shop structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the machine shop structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of preload
- Loss of sealing
- Loss of strength

Section 3.5.2.1.14

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Radwaste Facility as shown below.

Section 3.5.2.1.14, Radwaste Facility, page 3-700 is supplemented as follows.

3.5.2.1.14 Radwaste Facility

Environment

The radwaste facility structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the radwaste facility structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength

Section 3.5.2.1.15

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the SBO Building as shown below.

Section 3.5.2.1.15, SBO Building, page 3-701 is supplemented as follows.

3.5.2.1.15 SBO Building

Environment

The SBO building structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the SBO building structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength

Section 3.5.2.1.16

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Service Building as shown below.

Section 3.5.2.1.16, Service Building, page 3-702 is supplemented as follows.

3.5.2.1.16 Service Building

Environment

The service building structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the service building structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength

Section 3.5.2.1.17

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Turbine Building as shown below.

Section 3.5.2.1.17, Turbine Building, page 3-704 is supplemented as follows.

3.5.2.1.17 Turbine Building

Environment

The turbine building structural members are exposed to the following environments:

- Air
- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the turbine building structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength

Section 3.5.2.1.18

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Containment Spray Pump Building as shown below.

Section 3.5.2.1.18, Containment Spray Pump Building, page 3-706 is supplemented as follows.

3.5.2.1.18 Containment Spray Pump Building

Aging Effects Requiring Management

The following aging effects, associated with the containment spray pump building structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength

Section 3.5.2.1.19

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Fire Pump House as shown below.

Section 3.5.2.1.19, Fire Pump House, page 3-708 is supplemented as follows.

3.5.2.1.19 Fire Pump House

Aging Effects Requiring Management

The following aging effects, associated with the fire pump house structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength

Section 3.5.2.1.20

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Fuel Oil Pump House as shown below.

Section 3.5.2.1.20, Fuel Oil Pump House, page 3-710 is supplemented as follows.

3.5.2.1.20 Fuel Oil Pump House

Aging Effects Requiring Management

The following aging effects, associated with the fuel oil pump house structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of strength

Section 3.5.2.1.21

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Main Steam Valve House as shown below.

Section 3.5.2.1.21, Main Steam Valve House, page 3-711 is supplemented as follows.

3.5.2.1.21 Main Steam Valve House

Aging Effects Requiring Management

The following aging effects, associated with the main steam valve house structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of strength

Section 3.5.2.1.22

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Safeguards Building as shown below.

Section 3.5.2.1.22, Safeguards Building, page 3-712 is supplemented as follows.

3.5.2.1.22 Safeguards Building

Aging Effects Requiring Management

The following aging effects, associated with the safeguards building structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of strength

Section 3.5.2.1.23

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Buried Fuel Oil Tank Missile Barrier as shown below.

Section 3.5.2.1.23, Buried Fuel Oil Tank Missile Barrier, page 3-713 is supplemented as follows.

3.5.2.1.23 Buried Fuel Oil Tank Missile Barrier

Environment

The buried fuel oil tank missile barrier structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the buried fuel oil tank missile barrier structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of strength

Section 3.5.2.1.24

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Chemical Addition Tank Foundation as shown below.

Section 3.5.2.1.24, Chemical Addition Tank Foundation, page 3-714 is supplemented as follows.

3.5.2.1.24 Chemical Addition Tank Foundation

Environment

The chemical addition tank foundation structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the chemical addition tank foundation structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of strength
- Reduction in concrete anchor capacity

Section 3.5.2.1.25

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Duct Banks as shown below.

Section 3.5.2.1.25, Duct Banks, page 3-715 is supplemented as follows.

3.5.2.1.25 Duct Banks

Environment

The duct banks structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the duct banks structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of strength

Section 3.5.2.1.26

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Emergency Condensate Tank Foundations and Missile Barriers as shown below.

Section 3.5.2.1.26, Emergency Condensate Tank Foundations and Missile Barriers, page 3-716 is supplemented as follows.

3.5.2.1.26 Emergency Condensate Tank Foundations and Missile Barriers

Environment

The emergency condensate tank foundations and missile barriers structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the emergency condensate tank foundations and missile barriers structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength

Section 3.5.2.1.27

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Fire Protection and Domestic Water Tank Foundation as shown below.

Section 3.5.2.1.27, Fire Protection and Domestic Water Tank Foundation, page 3-717 is supplemented as follows.

3.5.2.1.27 Fire Protection and Domestic Water Tank Foundation

Environment

The fire protection and domestic water tank foundation structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the fire protection and domestic water tank foundation structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of strength

Section 3.5.2.1.28

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Fuel Oil Line Missile Barrier as shown below.

Section 3.5.2.1.28, Fuel Oil Line Missile Barrier, page 3-718 is supplemented as follows.

3.5.2.1.28 Fuel Oil Line Missile Barrier

Environment

The fuel oil line missile barrier structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the fuel oil line missile barrier structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of strength

Section 3.5.2.1.29

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Fuel Oil Storage Tank Dike as shown below.

Section 3.5.2.1.29, Fuel Oil Storage Tank Dike, page 3-719 is supplemented as follows.

3.5.2.1.29 Fuel Oil Storage Tank Dike

Environment

The fuel oil storage tank dike structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the fuel oil storage tank dike structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of strength

Section 3.5.2.1.30

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Manholes as shown below.

Section 3.5.2.1.30, Manholes, page 3-720 is supplemented as follows.

3.5.2.1.30 Manholes

Environment

The manholes structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the manholes structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of strength

Section 3.5.2.1.31

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Reactor Containment Subsurface Drainage System Access Shaft as shown below.

Section 3.5.2.1.31, Reactor Containment Subsurface Drainage System Access Shaft, page 3-721 is supplemented as follows.

3.5.2.1.31 Reactor Containment Subsurface Drainage System Access Shaft

Environment

The reactor containment subsurface drainage system access shaft structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the reactor containment subsurface drainage system access shaft structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material (spalling, scaling)
- Loss of strength

Section 3.5.2.1.32

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Refueling Water Storage Tank as shown below.

Section 3.5.2.1.32, Refueling Water Storage Tank, page 3-722 is supplemented as follows.

3.5.2.1.32 Refueling Water Storage Tank

Environment

The refueling water storage tank structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the refueling water storage tank structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of sealing
- Loss of strength
- Reduction in concrete anchor capacity

Section 3.5.2.1.33

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the SBO Structures for Offsite Power as shown below.

Section 3.5.2.1.33, SBO Structures for Offsite Power, page 3-723 is supplemented as follows.

3.5.2.1.33 SBO Structures for Offsite Power

Environment

The SBO structures for offsite power structural members are exposed to the following environments:

- Air – indoor uncontrolled
- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the SBO structures for offsite power structural members, require management:

- Change in material properties
- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of preload
- Loss of strength

Section 3.5.2.1.34

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Security Lighting Poles as shown below.

Section 3.5.2.1.34, Security Lighting Poles, page 3-725 is supplemented as follows.

3.5.2.1.34 Security Lighting Poles

Environment

The security lighting poles structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the security lighting poles structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of strength

Section 3.5.2.1.35

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements for the Transformer Firewalls and Dikes as shown below.

Section 3.5.2.1.35, Transformer Firewalls and Dikes, page 3-726 is supplemented as follows.

3.5.2.1.35 Transformer Firewalls and Dikes

Environment

The transformer firewalls and dikes structural members are exposed to the following environments:

- Air – outdoor
- Groundwater
- Soil
- Water – flowing

Aging Effects Requiring Management

The following aging effects, associated with the transformer firewalls and dikes structural members, require management:

- Cracking
- Cracking and distortion
- Increase in porosity and permeability
- Loss of bond
- Loss of material (spalling, scaling)
- Loss of material (spalling, scaling) and cracking
- Loss of strength

<u>Section 3.5.2.2.1.3</u>

This section is updated to clarify that the Containment liner includes liner anchors and integral attachments

Section 3.5.2.2.1.3, Loss of Material Due to General, Pitting and Crevice Corrosion, page 3-734 is supplemented as follows.

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).

[3.5.1-005] [3.5.1-035] – The ASME Section XI, Subsection IWE program (B2.1.29) manages aging of the steel liner of the concrete Containment building<u>, which includes liner anchors and integral attachments</u>. The 10 CFR Part 50, Appendix J program (B2.1.32) manages loss of leak tightness, loss of sealing, and leakage through Containment to assure that allowable leakage rate limits specified in the Technical Specifications are not exceeded. An evaluation of the acceptability of the inaccessible areas is completed whenever conditions are detected in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. A review of plant-specific operating experience associated with inaccessible areas from the ASME Section XI, Subsection IWE program (B2.1.29) has not identified any indications of corrosion. Operating experience associated with accessible areas from the ASME Section XI, Subsection IWE program (B2.1.29) has identified only minor indications of corrosion, which have been repaired by the corrective action program.

UFSAR Section 15.3.1 discusses concrete mix designs. Reinforced concrete structures at SPS were designed, constructed, and inspected in accordance with ACI and ASTM standards, which provide for a good quality, dense, well-cured, and low permeability concrete. The mix proportions were established in accordance with ACI-301, "Specifications for Structural Concrete for Buildings." The mix designs contain an air-entraining admixture capable of entraining three to five percent air in accordance with ASTM-C260, "Standard Specification for Air-Entraining Admixtures for Concrete" and maximum water content was controlled by placing the concrete at specified slumps. Procedural controls ensured quality throughout the batching, mixing, and placement processes. The ASME Section XI, Subsection IWL program (B2.1.30) identifies and manages any cracks in the containment concrete that could potentially provide a pathway for water to reach inaccessible portions of the steel containment liner. Crack control was achieved through proper sizing, spacing, and distribution of reinforcing steel in accordance with ACI 318-63, "Building Code Requirements for Reinforced Concrete." Therefore, a plant-specific aging management program to manage the effects of general, pitting and crevice corrosion is not required.

Section 3.5.2.2.1.6

This section is updated to clarify how the visual examinations will be augmented with surface examinations to manage cracking due to stress corrosion cracking for containment pressure boundary portions of the fuel transfer tube, fuel transfer tube enclosure, (blind flange) fuel transfer tube, and dissimilar metal weld penetrations.

Section 3.5.2.2.1.6, Cracking Due to Stress Corrosion Cracking, page 3-736 is supplemented as follows.

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 and10 CFR Part 50, Appendix J, to manage this aging effect. Further evaluation, including consideration of SCC susceptibility and applicable operating experience (OE) related to detection, is recommended of additional appropriate examinations/evaluations implemented to detect this aging effect for these SS components and dissimilar metal welds.

[3.5.1-010] – SPS does not have any stainless steel penetration bellows as part of the Containment pressure boundary. Stainless steel high energy pipes that penetrate the Containment are connected to carbon steel penetration sleeves with dissimilar metal welds. Plant operating experience has not identified any stress corrosion cracking associated with these welds. The ASME Section XI, Subsection IWE program (B2.1.29) and the 10 CFR Part 50, Appendix J program (B2.1.32) manage the aging of these dissimilar metal welds. Visual examinations are augmented with ~~additional examinations, as necessary, to detect cracking in these welds. No augmented examinations have been required.~~ <u>surface examinations to manage cracking due to stress corrosion cracking for containment pressure boundary portions of the fuel transfer tube, fuel transfer tube enclosure, blind flange (fuel transfer tube), and dissimilar metal weld penetrations. The fuel transfer tube and bellows (expansion joint) are evaluated as part of the fuel handling system (2.3.3.1). Surface examinations will be performed once during each ten year interval.</u>

Section 3.5.2.2.2.4

This section is updated to clarify management of stainless steel and aluminum components in air.

Section 3.5.2.2.2.4, Cracking Due to Stress Corrosion Cracking, and Loss of Material Due to Pitting and Crevice Corrosion, pages 3-745 and 3-746 are supplemented as follows.

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.*

[3.5.1-052] – There are no stainless steel tank liners that are within the scope of subsequent license renewal for SPS.

[3.5.1-099] – Plant-specific OE has identified pitting or crevice corrosion or cracking for stainless steel piping components exposed to air or condensation (see Further Evaluation 3.4.2.2.2). The ASME Section XI, Subsection IWF program (B2.1.31) will manage the aging of stainless steel component supports to ensure that these components continue to perform their intended functions during the subsequent period of extended operation. There are no aluminum support components that are within the scope of the ASME Section XI, Subsection IWF program (B2.1.31).

[3.5.1-100] – Plant-specific OE has identified pitting or crevice corrosion or cracking for stainless steel piping components exposed to air or condensation (see Further Evaluation 3.4.2.2.2). The Structures Monitoring program (B2.1.34) will manage the aging of stainless steel ~~component supports and sump liners,~~ and aluminum alloy components~~component supports~~ to ensure that these components continue to perform their intended functions during the subsequent period of extended operation.

Table 3.5.1

[3.5.1-005], [3.5.1-010], [3.5.1-027], [3.5.1-028], [3.5.1-029], [3.5.1-030], [3.5.1-031], and [3.5.1-035] are updated to identify that exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B2.1.29) program implementation.

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below, item [3.5.1-020].

[3.5.1-026] is updated to N/A as discussed in the IWE program.

[3.5.1-093] and [3.5.1-095] are updated to clarify the applicable Table 1 item for galvanized steel.

Table 3.5.1, Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapter II and III of the GALL-SLR Report, pages 3-751, 3-752, 3-754, 3-755, 3-756, and 3-766 are supplemented as follows.

Table 3.5.1 Summary of Aging Management Programs for Containments, Structures and Component Supports Evaluated in Chapter II and III of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	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 (SRP-SLR Section 3.5.2.2.1.3.1)	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B2.1.29) program implementation. See further evaluation in Section 3.5.2.2.1.3.1.

3.5.1-010	Penetration sleeves; penetration bellows	Cracking due to SCC	AMP XI.S1, ASME Section XI, Subsection IWE, and AMP XI.S4, 10 CFR Part 50, Appendix J	Yes (SRP-SLR Section 3.5.2.2.1.6)	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B2.1.29) program implementation. In addition to the Containment Structure, components in Auxiliary Systems (Fuel Handling) are aligned to this item. See further evaluation in Section 3.5.2.2.1.6.
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. See further evaluation in Section 3.5.2.2.1.9.~~ Consistent with NUREG-2191.
3.5.1-026	Moisture barriers (caulking, flashing, and other sealants)	Loss of sealing due to wear, damage, erosion, tear, surface cracks, other defects	AMP XI.S1, ASME Section XI, Subsection IWE	No	~~Consistent with NUREG-2191.~~ Not applicable. As discussed in B2.1.29, the IWE Program does not include a moisture barrier.
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	No	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B2.1.29) program implementation. In addition to Containment Structure, components in Auxiliary Systems (Fuel Handling) are aligned to this item.
3.5.1-028	Personnel airlock, equipment hatch, CRD hatch	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, ASME Section XI, Subsection IWE, and AMP XI.S4, 10 CFR Part 50, Appendix J	No	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B2.1.29) program implementation.
3.5.1-029	Personnel airlock, equipment hatch, CRD hatch: locks, hinges, and closure mechanisms	Loss of leak tightness due to mechanical wear	AMP XI.S1, ASME Section XI, Subsection IWE, and AMP XI.S4, 10 CFR Part 50, Appendix J	No	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B2.1.29) program implementation.

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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B2.1.29) program implementation.
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 with exceptions. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B2.1.29) program implementation.
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	Loss of material due to general, pitting, crevice corrosion	AMP XI.S1, ASME Section XI, Subsection IWE, and AMP XI.S4, 10 CFR Part 50, Appendix J	Yes (SRP-SLR Section 3.5.2.2.1.3.1)	Consistent with NUREG-2191 with exceptions. Exceptions apply to the NUREG-2191 recommendations for ASME Section XI, Subsection IWE (B2.1.29) program implementation. See further evaluation in Section 3.5.2.2.1.3.1.
3.5.1-093	Galvanized steel support members; welds; bolted connections; support anchorage to building structure	Loss of material due to pitting, crevice corrosion	AMP XI.S6, Structures Monitoring	No	Not applicable. Galvanized steel components are evaluated using NUREG-2191 items for Steel. Refer to Item Number 3.5.1-092. The associated NUREG-2191 aging items are not used.
3.5.1-095	Galvanized steel support members; welds; bolted connections; support anchorage to building structure	None	None	No	Not applicable. Galvanized steel components are evaluated using NUREG-2191 items for Steel. Refer to Item Number 3.5.1-092. The associated NUREG-2191 aging items are not used.

Table 3.5.2-1

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements, to update the NUREG-2191 consistency note used for the ASME Section XI, Subsection IWE program and Structures Monitoring program, and to clarify management of stainless steel components in air, as shown below.

This section is updated to add plant specific notes to clarify that Containment liner includes liner anchors and integral attachments and for O-rings to clarify specific included components. An AMR line is added for loss of material for mechanical penetration dissimilar metal welds. "Caulking and sealants" is removed from the table as it is not applicable since a moisture barrier is not installed between Containment liner-concrete interface. This section is also updated to change consistency note A to B for the ASME Section XI, Subsection IWE program, and to credit the Structures Monitoring program instead of One-Time Inspection for management of stainless steel in air, and to delete note 5 that described use of the One-Time Inspection program.

Table 3.5.2-1, Containments, Structures and Component Supports - Containment - Aging Management Evaluation, pages 3-770, 3-772, 3-773, 3-774, 3-775, 3-776, and 3-777 are supplemented as follows.

Table 3.5.2-1 Containments, Structures and Component Supports - Containment - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Bolting	SS	Steel	(E) Air – indoor uncontrolled	Loss of material	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-148	3.5.1-031	~~A~~ B
				Loss of preload	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-150	3.5.1-030	~~A~~ B
			(E) Air – outdoor	Loss of material	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-148	3.5.1-031	~~A~~ B
				Loss of preload	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-150	3.5.1-030	~~A~~ B
Concrete elements	EN;FB;FLB; JIS;MB;PB; SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	ASME Section XI, Subsection IWL (B2.1.30)	II.A1.CP-32	3.5.1-020	A;1
					Structures Monitoring (B2.1.34)	III.A1.TP-24	3.5.1-063	A;1
~~Caulking and sealants~~	~~EN;PB~~	~~Elastomer, rubber and other similar materials~~	~~(E) Air – indoor uncontrolled~~	~~Loss of sealing~~	~~ASME Section XI, Subsection IWE (B2.1.29)~~	~~II.A3.CP-40~~	~~3.5.1-026~~	A
					~~10 CFR Part 50, Appendix J (B2.1.32)~~	~~II.A3.CP-41~~	~~3.5.1-033~~	A
			~~(E) Air – outdoor~~	~~Loss of sealing~~	~~10 CFR Part 50, Appendix J (B2.1.32)~~	~~II.A3.CP-41~~	~~3.5.1-033~~	A

Containment liner	PB;SS	Steel	(E) Air – indoor uncontrolled	Cumulative fatigue damage (Only if CLB fatigue analysis exists)	TLAA	II.A3.C-13	3.5.1-009	A, 8
				Loss of material	10 CFR Part 50, Appendix J (B2.1.32)	II.A1.CP-98	3.5.1-005	A, 8
					ASME Section XI, Subsection IWE (B2.1.29)	II.A1.CP-98	3.5.1-005	~~A~~ B, 8
					10 CFR Part 50, Appendix J (B2.1.32)	II.A1.CP-35	3.5.1-035	A, 8
					ASME Section XI, Subsection IWE (B2.1.29)	II.A1.CP-35	3.5.1-035	~~A~~ B, 8
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	C, 8
Containment sump liner	PB;SS	Stainless steel	~~(E) Water – standing~~ (E) Air	Cracking; loss of material	~~One-Time Inspection (B2.1.20)~~ Structures Monitoring (B2.1.34)	~~III.A7.T-23~~ III.B2.T-37b	~~3.5.1-052~~ 3.5.1-100	~~E, 5~~ C
Door locking mechanism	PB;SS	Steel	(E) Air – indoor uncontrolled	Loss of leak tightness	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-39	3.5.1-029	~~A~~ B
			(E) Air – outdoor	Loss of leak tightness	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-39	3.5.1-029	~~A~~ B

Equipment hatch	PB;SS;EN;MB	Steel	(E) Air – indoor uncontrolled	Cracking (CLB fatigue analysis does not exist)	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	~~A~~ B
				Loss of leak tightness	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-39	3.5.1-029	~~A~~ B
				Loss of material	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.C-16	3.5.1-028	~~A~~ B
			E) Air – outdoor	Cracking (CLB fatigue analysis does not exist)	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	~~A~~ B
				Loss of leak tightness	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-39	3.5.1-029	~~A~~ B
				Loss of material	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.C-16	3.5.1-028	~~A~~ B
Equipment hatch air lock doors	PB;SS;EN;MB	Steel	(E) Air – indoor uncontrolled	Cracking (CLB fatigue analysis does not exist)	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	~~A~~ B
				Loss of leak tightness	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-39	3.5.1-029	~~A~~ B
				Loss of material	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.C-16	3.5.1-028	~~A~~ B

			E) Air – outdoor	Cracking (CLB fatigue analysis does not exist)	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	~~A~~ B
				Loss of leak tightness	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-39	3.5.1-029	~~A~~ B
				Loss of material	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.C-16	3.5.1-028	~~A~~ B
Hinges and pins	PB;SS	Steel	(E) Air – indoor uncontrolled	Loss of leak tightness	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-39	3.5.1-029	~~A~~ B
			(E) Air – outdoor	Loss of leak tightness	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-39	3.5.1-029	~~A~~ B
O-rings	PB;SS	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-41	3.5.1-033	A, 9
Penetrations (electrical)	SS;EN;PB	Dissimilar metal welds	(E) Air – indoor uncontrolled	Loss of material	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	~~A~~ B
				Loss of material	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-36	3.5.1-035	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-36	3.5.1-035	~~A~~ B
			(E) Air with borated water leakage	Loss of material	Boric Acid Corrosion (B2.1.4)	III.B5.T-25	3.5.1-089	C

Penetrations (mechanical)	SS;EN;PB	Dissimilar metal welds	(E) Air – indoor uncontrolled	Cracking	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-38	3.5.1-010	~~A~~ B
				Cracking (CLB fatigue analysis does not exist)	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-37	3.5.1-027	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	B
				Loss of material	10 CFR Part 50, Appendix J (B2.1.32)	II.A3.CP-36	3.5.1-035	A
					ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-36	3.5.1-035	B
		Steel	(E) Air – indoor uncontrolled	Cracking (CLB fatigue analysis does not exist)	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	~~A~~ B
				Loss of material	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-36	3.5.1-035	~~A~~ B
Personnel hatch	PB;SS;EN	Steel	(E) Air – indoor uncontrolled	Cracking (CLB fatigue analysis does not exist)	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	~~A~~ B
				Loss of leak tightness	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-39	3.5.1-029	~~A~~ B
				Loss of material	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.C-16	3.5.1-028	~~A~~ B
			(E) Air – outdoor	Cracking (CLB fatigue analysis does not exist)	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-37	3.5.1-027	~~A~~ B
				Loss of leak tightness	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.CP-39	3.5.1-029	~~A~~ B

				Loss of material	ASME Section XI, Subsection IWE (B2.1.29)	II.A3.C-16	3.5.1-028	~~A~~ B

Table 3.5.2-1 Plant-Specific Notes:

5. ~~The plant-specific aging management program used to manage the applicable aging effect(s) for this component type, material, and environment combination is the One-Time Inspection (B2.1.20) program.~~ Not used.

8. Containment liner includes liner anchors and integral attachments.

9. O-rings includes seals and gaskets for air lock doors, penetration flanges, fuel transfer blank flanges, and other elastomer materials that are part of the containment pressure boundary.

Table 3.5.2-2

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-2, Containments, Structures and Component Supports – Auxiliary Building Structure - Aging Management Evaluation, page 3-779, is supplemented as follows.

Table 3.5.2-2 Containments, Structures and Component Supports – Auxiliary Building Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;1

Table 3.5.2-5

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below. It is also updated to add an AMR line for the spent fuel pool liner TLAA and to add a plant specific note pointing to the section that contains the TLAA evaluation.

Table 3.5.2-5, Containments, Structures and Component Supports - Fuel Building Structure - Aging Management Evaluation, pages 3-787 and 3-788, is supplemented as follows.

Table 3.5.2-5 Containments, Structures and Component Supports - Fuel Building Structure - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FLB;MB; SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A5.TP-24	3.5.1-063	A;1
Spent fuel pool liner plates	PB;SS;EN	Stainless steel	(E) Treated borated water	Cumulative fatigue damage	TLAA	None	None	H:6

Table 3.5.2-5 Plant-Specific Notes:

6. The evaluation of fuel pool liner plate fatigue is addressed in Section 4.7.4, Spent Fuel Pool Liner Fatigue Analysis.

Table 3.5.2-9

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-9, Containments, Structures and Component Supports - Black Battery Building- Aging Management Evaluation, page 3-799, is supplemented as follows.

Table 3.5.2-9 Containments, Structures and Component Supports - Black Battery Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A:2

Table 3.5.2-10

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-10, Containments, Structures and Component Supports - Central Alarm Station - Aging Management Evaluation, page 3-801, is supplemented as follows.

Table 3.5.2-10 Containments, Structures and Component Supports - Central Alarm Station- Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-11

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-11, Containments, Structures and Component Supports - Condensate Polishing Building - Aging Management Evaluation, page 3-803, is supplemented as follows.

Table 3.5.2-11 Containments, Structures and Component Supports - Condensate Polishing Building- Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-12

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-12, Containments, Structures and Component Supports - Laundry Facility - Aging Management Evaluation, page 3-806, is supplemented as follows.

Table 3.5.2-12 Containments, Structures and Component Supports - Laundry Facility - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;1

Table 3.5.2-13

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-13, Containments, Structures and Component Supports - Machine Shop - Aging Management Evaluation, page 3-807, is supplemented as follows.

Table 3.5.2-13 Containments, Structures and Component Supports - Machine Shop - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-14

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-14, Containments, Structures and Component Supports - Radwaste Facility - Aging Management Evaluation, page 3-810, is supplemented as follows.

Table 3.5.2-14 Containments, Structures and Component Supports - Radwaste Facility - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-15

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-15, Containments, Structures and Component Supports - SBO Building - Aging Management Evaluation, page 3-812, is supplemented as follows.

Table 3.5.2-15 Containments, Structures and Component Supports - SBO Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-16

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below. Additionally, a note for flood dikes is being added to clarify specific included components.

Table 3.5.2-16, Containments, Structures and Component Supports - Service Building - Aging Management Evaluation, pages 3-814 and 3-815 are supplemented as follows.

Table 3.5.2-16 Containments, Structures and Component Supports - Service Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB; MB;PB;SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2
Flood dikes	FLB	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A;4

Table 3.5.2-16 Plant-Specific Notes:

4. Includes steel dikes, shields, and deflectors

Table 3.5.2-17

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below. Additionally, a note for flood dikes is being added to clarify specific included component

Table 3.5.2-17, Containments, Structures and Component Supports - Turbine Building - Aging Management Evaluation, pages 3-817 and 3-818, are supplemented as follows.

Table 3.5.2-17 Containments, Structures and Component Supports - Turbine Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB; MB;PB;SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2
Flood dikes	FLB	Steel	(E) Air – indoor uncontrolled	Loss of material	Structures Monitoring (B2.1.34)	III.A3.TP-302	3.5.1-077	A;4

Table 3.5.2-17 Plant-Specific Notes:

4. Includes steel dikes, shields, and deflectors

Table 3.5.2-18

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-18, Containments, Structures and Component Supports - Containment Spray Pump Building - Aging Management Evaluation, page 3-820, is supplemented as follows.

Table 3.5.2-18 Containments, Structures and Component Supports - Containment Spray Pump Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;MB; SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-19

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-19, Containments, Structures and Component Supports - Fire Pump House - Aging Management Evaluation, page 3-822, is supplemented as follows.

Table 3.5.2-19 Containments, Structures and Component Supports - Fire Pump House - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	FB;FLB;MB; SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-20

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-20, Containments, Structures and Component Supports - Fuel Oil Pump House - Aging Management Evaluation, page 3-824, is supplemented as follows.

Table 3.5.2-20 Containments, Structures and Component Supports - Fuel Oil Pump House - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-21

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-21, Containments, Structures and Component Supports - Main Steam Valve House - Aging Management Evaluation, page 3-826, is supplemented as follows.

Table 3.5.2-21 Containments, Structures and Component Supports - Main Steam Valve House - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;JIS; MB;SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-22

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-22, Containments, Structures and Component Supports - Safeguards Building - Aging Management Evaluation, page 3-828, is supplemented as follows.

Table 3.5.2-22 Containments, Structures and Component Supports - Safeguards Building - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;FB;FLB; MB;SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-23

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-23, Containments, Structures and Component Supports - Buried Fuel Oil Tank Missile Barrier - Aging Management Evaluation, page 3-829, is supplemented as follows.

Table 3.5.2-23 Containments, Structures and Component Supports - Buried Fuel Oil Tank Missile Barrier - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	SS;MB	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-24

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-24, Containments, Structures and Component Supports - Chemical Addition Tank Foundation - Aging Management Evaluation, page 3-830, is supplemented as follows.

Table 3.5.2-24 Containments, Structures and Component Supports - Chemical Addition Tank Foundation - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-25

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-25, Containments, Structures and Component Supports - Duct Banks - Aging Management Evaluation, page 3-832, is supplemented as follows.

Table 3.5.2-25 Containments, Structures and Component Supports - Duct Banks - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-26

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-26, Containments, Structures and Component Supports - Emergency Condensate Tank Foundations and Missile Barriers - Aging Management Evaluation, page 3-834, is supplemented as follows.

Table 3.5.2-26 Containments, Structures and Component Supports - Emergency Condensate Tank Foundations and Missile Barriers - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;MB;SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-27

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-27, Containments, Structures and Component Supports - Fire Protection and Domestic Water Tank Foundation - Aging Management Evaluation, page 3-835, is supplemented as follows.

Table 3.5.2-27 Containments, Structures and Component Supports - Fire Protection and Domestic Water Tank Foundation - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-28

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-28, Containments, Structures and Component Supports - Fuel Oil Line Missile Barrier - Aging Management Evaluation, page 3-836, is supplemented as follows.

Table 3.5.2-28 Containments, Structures and Component Supports - Fuel Oil Line Missile Barrier - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;MB;SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-29

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-29, Containments, Structures and Component Supports - Fuel Oil Storage Tank Dike - Aging Management Evaluation, page 3-837, is supplemented as follows.

Table 3.5.2-29 Containments, Structures and Component Supports - Fuel Oil Storage Tank Dike - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	FLB;SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-30

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-30, Containments, Structures and Component Supports - Manholes - Aging Management Evaluation, page 3-838, is supplemented as follows.

Table 3.5.2-30 Containments, Structures and Component Supports - Manholes - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	MB;SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-31

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-31, Containments, Structures and Component Supports - Reactor Containment Subsurface Drainage System Access Shaft - Aging Management Evaluation, page 3-840, is supplemented as follows.

Table 3.5.2-31 Containments, Structures and Component Supports - Reactor Containment Subsurface Drainage System Access Shaft - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-32

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-32, Containments, Structures and Component Supports - Refueling Water Storage Tank Foundation - Aging Management Evaluation, page 3-841, is supplemented as follows.

Table 3.5.2-32 Containments, Structures and Component Supports - Refueling Water Storage Tank Foundation - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-33

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-33, Containments, Structures and Component Supports - SBO Structures for Offsite Power - Aging Management Evaluation, page 3-844, is supplemented as follows.

Table 3.5.2-33 Containments, Structures and Component Supports - SBO Structures for Offsite Power - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	EN;SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-34

This section is updated to clarify management of the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for concrete elements as shown below.

Table 3.5.2-34, Containments, Structures and Component Supports - Security Lighting Poles - Aging Management Evaluation, page 3-846, is supplemented as follows.

Table 3.5.2-34 Containments, Structures and Component Supports - Security Lighting Poles - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-35

This section is updated to clarify management of the aging effect, "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation," for concrete elements as shown below.

Table 3.5.2-35, "Containments, Structures and Component Supports - Transformer Firewalls and Dikes- Aging Management Evaluation," page 3-847, is supplemented as follows:

Table 3.5.2-35 Containments, Structures and Component Supports - Transformer Firewalls and Dikes - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Concrete elements	FB;FLB;SS	Concrete	(E) Water – flowing	Increase in porosity and permeability; loss of strength	Structures Monitoring (B2.1.34)	III.A3.TP-24	3.5.1-063	A;2

Table 3.5.2-37

This section is updated to clarify the flood barrier intended function as applicable for fire barrier seals and penetrations seals, and to specify management of stainless steel in air by the Structures Monitoring program.

Table 3.5.2-37, "Containments, Structures and Component Supports - Miscellaneous Structural Commodities - Aging Management Evaluation," page 3-851, is supplemented as follows:

Table 3.5.2-37 Containments, Structures and Component Supports - Miscellaneous Structural Commodities - Aging Management Evaluation

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Fire barrier seals	FB;FLB	Cerafiber, pyrocrete, micarta, dux seal, KBS sealbags, mineral wool, gypsum	(E) Air – indoor uncontrolled	Loss of material, change in material properties, cracking/delamination, separation	Fire Protection (B2.1.15)	None	None	E, 2
		Elastomer	(E) Air	Hardening, loss of strength, shrinkage	Fire Protection (B2.1.15)	VII.G.A-19	3.3.1-057	A
Penetration seals	EN;FLB;PB	Elastomer, rubber and other similar materials	(E) Air – indoor uncontrolled	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Air – outdoor	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Groundwater	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
			(E) Soil	Loss of sealing	Structures Monitoring (B2.1.34)	III.A6.TP-7	3.5.1-072	A
Radiant energy shields	FB	Stainless steel	(E) Air	Loss of material; cracking	~~Fire Protection (B2.1.15)~~ Structures Monitoring (B2.1.34)	III.B2.T-37b	3.5.1-100	~~E, 2~~ C

4.2 REACTOR VESSEL NEUTRON EMBRITTLEMENT ANALYSIS

10 CFR 50.60, "Acceptance Criteria for Fracture Prevention Measures for Lightwater Nuclear Reactors for Normal Operation," requires that all light water reactors meet the fracture toughness, P-T limits, and materials surveillance program requirements for the reactor coolant pressure boundary as set forth in 10 CFR 50, Appendices G and H. The materials included in the surveillance capsule program remain unchanged for the subsequent period of extended operation based upon the provisions outlined in earlier versions of ASTM E185, "Standard Practice for Design of Surveillance Programs for Light-Water Moderated Nuclear Power Reactor Vessels" (Reference 4.8-1) that existed at the time of initial plant construction. 10 CFR 50.61 requires that all light water reactors meet the fracture toughness requirements for protection against pressurized thermal shock events. The *Reactor Vessel Material Surveillance* program is described in Section B2.1.19.

Inputs for reactor vessel (RV) integrity assessments are discussed in this section.

The best estimate copper (Cu) and nickel (Ni) chemical compositions for the Units 1 and 2 RV materials are presented in Table 4.2.2-1 through Table 4.2.2-4. The best estimate weight percent Cu and Ni values for the RV materials were reported in PWROG-16045-NP, "Determination of Unirradiated RT_{NDT} and Upper-Shelf Energy Values of the Units 1 and 2 Reactor Vessel Materials" (Reference 4.8-2) and were included in RV integrity evaluations as part of this TLAA effort.

Prior to updating the RV integrity assessments for the subsequent period of extended operation both the fluence projections and material properties were reviewed and updated by WCAP-18028-NP, "Extended Beltline Pressure Vessel Fluence Evaluations Applicable to Surry Units 1 & 2" (Reference 4.8-3), WCAP-18242-NP, "Surry Units 1 and 2 Time Limited Aging Analysis on Reactor Vessel Integrity for Subsequent License Renewal" (Reference 4.8-4) and PWROG-16045-NP. Revised initial material properties, including chemistry factors and fluence projections, through 68 EFPY are included in Table 4.2.3-1 and Table 4.2.3-2 for Units 1 and 2 respectively.

The neutron fluence axial boundary of the 1.0×10^{17} n/cm^2 fluence threshold is depicted in Figures 4.2.2-1 and 4.2.2-2 for Units 1 and 2 respectively. The configuration of the RVs, including the weld identification (ID) numbers, is illustrated in Figures 4.2.2-3 and 4.2.2-4 for Units 1 and 2, respectively.

Reactor vessel integrity assessments are performed for both the beltline region (identified in 10 CFR 50, Appendix G) and extended beltline region (fluence values $>1.0 \times 10^{17}$ n/cm^2, E >1 MeV).

The beltline region is the region of the RV (shell material, including welds, heat-affected zones, and plate or forgings) that directly surrounds the effective height of the active core and the adjacent

4.2.5 PRESSURE-TEMPERATURE LIMITS

TLAA Description:

10 CFR 50 Appendix G requires that the RV be maintained within established pressure-temperature (P-T) limits, including heatup and cooldown operations. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. As the RV is exposed to increased neutron irradiation, its fracture toughness is reduced. The P-T limits must account for the anticipated RV fluence.

The current P-T limits are based upon fluence projections for 60 years of plant operation. Because they were based upon a fluence assumption of 60 years of operation, the P-T limits analyses meet the definition of 10 CFR 54.3(a) (Reference 1.7-2) and have been identified as TLAAs.

TLAA Evaluation:

Heatup and cooldown limit curves are calculated using the most limiting value of RT_{NDT} corresponding to the limiting material in the beltline region of the RV. The most limiting RT_{NDT} of the material in the core region (beltline) of the RV is determined by using the unirradiated RV material fracture toughness properties and estimating the irradiation induced shift (ΔRT_{NDT}).

RT_{NDT} increases as the material is exposed to fast neutron irradiation; therefore, to find the most limiting core region (beltline) RT_{NDT} at any time, ΔRT_{NDT} due to the neutron radiation exposure associated with that time must be added to the original unirradiated RT_{NDT}. Using the ART values, P-T limit curves are determined in accordance with the requirements of 10 CFR Part 50, Appendix G, as augmented by ASME Code, Section XI, Appendix G.

The P-T limits for 48 EFPY (currently maintained in the Technical Specifications for Units 1 and 2) are based on the K_{Ia} methodology and the latest fluence data.~~The current P-T limits for Units 1 and 2 are based on the Kla methodology and the latest fluence data through 48 EFPY and are maintained in the Technical Specifications.~~

According to NUREG-2192, Section 4.2.2.1.4, the P-T limits for the subsequent period of extended operation need not be submitted as part of the SLRA since the P-T limits are required to be updated through the 10 CFR 50.90 licensing process when necessary for P-T limits that are located in the Technical Specifications. The current licensing basis will ensure that the P-T limits for the subsequent period of extended operation will be updated prior to exceeding the EFPY for which they remain valid.

Nozzle materials were evaluated in WCAP-18242-NP at 48 EFPY and 68 EFPY; the nozzle forging materials evaluated are documented in Tables 4.2.4-1, 4.2.4-3, 4.2.2-5, and e. All nozzle materials were assigned the fluence values at the postulated 1/4T flaw location for each specific nozzle in Table 4.2.1-1 and Table 4.2.1-2. Thus, Unit 1 Inlet Nozzle 1 and Unit 2 Inlet Nozzle 1 and Outlet Nozzle 3 have neutron fluence values greater than 1.0×10^{17} n/cm^2 (E > 1.0 MeV) at 68 EFPY. In order to fully assess the Units 1 and 2 P-T limit curves applicability to 68 EFPY, a nozzle corner fracture mechanics analysis was completed for all nozzle materials. These nozzle P-T limit curves were generated and compared to the beltline P-T limit curves to ensure that the beltline curves are bounding. The detailed nozzle forging fracture mechanics evaluation and comparison to the applicable RV beltline P-T limit curves were documented in WCAP-18243-NP. The current beltline curves were confirmed to remain more limiting than the nozzle curves through 68 EFPY.

The development of the ~~current~~ 48 EFPY P-T limit curves for normal heatup and cooldown of the primary reactor coolant system for Units 1 and 2 was documented in WCAP-14177. The ~~existing~~ P-T limit curves developed for 68 EFPY in WCAP-18243 are based on the K_{Ic} methodology and the limiting beltline material ART values, which are influenced by both the fluence and the initial material properties of that material. The Units 1 and 2 P-T limit curves were developed by calculating ART values utilizing the vessel fluence at the clad/base metal interface corresponding to each RV material. Since the development of the curves, the applicability of the curves has been extended and the fluence values and initial material properties used to calculate ART values have been updated.

The K_{Ic} methodology was used to confirm the applicability of the P-T limit curves developed based on WCAP-14177. The limiting RV material ART values with consideration of the updated 68 EFPY fluence values, revised Position 2.1 chemistry factor values, and updated initial RT_{NDT} values must be shown to be less than or equal to the limiting beltline material ART values used in development of the P-T limit curves contained in WCAP-14177 and the Units 1 and 2 Technical Specifications. The Regulatory Guide 1.99 methodology was used along with the surface fluence of Section 2 of WCAP-18242-NP to calculate ART values for the Units 1 and 2 RV materials at 48 EFPY and 68 EFPY.

Comparisons of the use of the K_{Ic} reference stress intensity factor, instead of the older, more conservative K_{Ia} reference stress intensity factor were conducted to validate that the PT limits for 48 EFPY are conservative for operation through the subsequent period of extended operation. The comparisons of the limiting ART values calculated as part of this RV integrity TLAA evaluation, using updated fluence and initial material properties, to those used in calculation of the existing P-T limit curves are contained in Table 4.2.4-9 for Units 1 and 2. With the consideration of TLAA fluence projections, the applicability of the P-T limit curves in WCAP-14177 may be extended to 68 EFPY for the Units 1 and 2 cylindrical shell materials. Nozzle P-T limit curves were developed per WCAP-18243-NP and compared to the cylindrical shell beltline curves. ART values were generated without the consideration of the methodology in TLR-RES/DE/CIB-2013-01, "Evaluation of the Beltline Region for Nuclear Reactor Pressure Vessels, U.S. NRC Technical Letter Report, Office of Nuclear Regulatory Research [RES]" (Reference 4.8-36). Per WCAP-18243-NP, the applicability of the P-T limit curves may be extended through SLR, because the current Technical Specifications P-T limit curves bound the new P-T limit curves developed in WCAP-18243-NP regardless of the use of the TLR-RES/DE/CIB-2013-01 methodology. Per WCAP-18243-NP, the applicability of the P-T limit curves may be extended through the subsequent period of extended operation.

In addition, the applicable RV flange and closure head initial RT_{NDT} values are bounding and the P-T limit curves flange notch requires no change or further consideration. Finally, the lowest service temperature requirements are not applicable to Units 1 and 2, because the plants are Westinghouse-designed per ASME Code, Section III, and utilize stainless steel reactor coolant system piping.

TLAA Disposition: 10 CFR 54.21(c)(1)(iii)

Since the P-T limits will be updated through the 10 CFR 50.90 process at a later, appropriate date, the effects of aging on the intended function(s) of the RVs will be adequately managed for the subsequent period of extended operation. The *Reactor Vessel Material Surveillance* program (B2.1.19) and plant Technical Specifications will ensure that updated P-T limits based upon updated ART values will be submitted to the NRC for approval prior to exceeding the period of applicability for Units 1 and 2.

4.2.6 LOW TEMPERATURE OVERPRESSURE PROTECTION

TLAA Description:

Low temperature overpressure protection (LTOP) system (sometimes referred to as the Reactor Coolant System Overpressure Mitigating System, or the RV Overpressure Mitigating System) at Unit 1 and Unit 2 is required by Technical Specification Limited Condition for Operation 3.1.G. Two pressurizer power operated relief valves (PORV) provide the automatic relief capability during the design basis mass input and the design basis heat input transients to automatically prevent the reactor coolant system pressure from exceeding the P-T limit curves based on 10 CFR 50, Appendix G.

LTOP system setpoints are based on the P-T limits calculation which is a TLAA.

TLAA Evaluation:

The LTOP enabling temperature has been determined for 68 EFPY as discussed in Appendix D of WCAP-18243-NP. Using Code Case N-514, the LTOP enabling temperature is 283°F. The Surry Technical Specification 3.1.G.1.c.(4) specifies an arming temperature of 350°F which is conservative and remains valid for the subsequent period of extended operation.

In WCAP-~~18242~~18243-NP the maximum allowable LTOP system PORV setpoint was calculated to be 399.6 psig for the Units 1 and 2 subsequent period of extended operation. The calculation was performed in accordance with the WCAP-14040-A methodology using LTOP input parameters and the limiting axial flaw steady state ASME Code, Section XI, Appendix G limits calculated for the subsequent period of extended operation at 68 EFPY.

Table 4.3.3-1 80 Year Transient Cycle Projections for ANSI B31.1 Piping

Description	Conservative Basis for Cycle Projection	Projected Cycles for 80 years
Auxiliary Steam	Stripper feed heat exchanger kept in warm steady state condition. Assume 50 to 75 cycles per year.	Less than 7,000 cycles
Blowdown	Continuous blowdown during power operations. RCS transients from Table 4.3.1-1.	Less than 7,000 cycles
Boron Recovery	Stripper feed heat exchanger kept in warm steady state condition by Auxiliary Steam. Assume 50 to 75 cycles per year (80 years x 75 cycles/year = 6,000 cycles).	Less than 7,000 cycles
Chemical and Volume Control	Normal Charging and Letdown during the RCS power operation at steady state temperature. Conservatively assume 2 cycles per year.	Less than 1,000 cycles
Condensate	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1.	Less than 7,000 cycles
Containment Vacuum and Leakage Monitoring	Auxiliary Steam to the Containment Vacuum Ejectors used from cold shutdown to intermediate shutdown – once per 18 months plus margin = 100 cycles.	Less than 1,000 cycles
Emergency Diesel Generator (Exhaust)	One start per month plus transients and pre-operational testing.	Less than 2,000 cycles
Alternate AC Diesel Generator (Exhaust)	One start per quarter for testing equal 320 cycles.	Less than 1,000 cycles
Security Diesel Generator (Exhaust)	One start per month – 960 cycles.	Less than 2,000 cycles
Extraction Steam	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1.	Less than 7,000 cycles
Feedwater	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1.	Less than 7,000 cycles
Fire Protection	Fire pump diesel engine exhaust cycles only during pump testing every 31 days. (12 cycles/year x 80 years = 960 cycles).	Less than 2,000 cycles
Fuel Pool Cooling	Pressure cycles for refueling canal draining and refilling are associated with plant refueling and are estimated based upon one refueling canal pressure cycle resulting in one plant heatup cycle. Table 4.3.1-1 indicates that Unit 1 has the greatest estimated 80 year heatup cycles of 165 cycles.	Less than 7,000 cycles
Generator Nitrogen	Piping connected to Steam Generators exposed to similar cycles as RCS from Table 4.3.1-1.	Less than 7,000 cycles
Heating Steam	Cycles based on seasonal heating. Conservatively assume 85 cycles per year (80 years x 85/year = 6,800 cycles).	Less than 7,000 cycles
Main Steam	Transients relative to power cycle operation consistent with RCS transients from Table 4.3.1-1.	Less than 7,000 cycles
Reactor Coolant	RCS transients from Table 4.3.1-1.	Less than 7,000 cycles
Recirculation Spray	Thermal cycle during design basis accident only (transient).	Less than 7,000 cycles
Residual Heat Removal	System piping heated during shutdowns and startups. 2 per heatup and cooldown each refueling cycle.	Less than 2,000 cycles

4.3.4 ENVIRONMENTALLY-ASSISTED FATIGUE

TLAA Description:

As outlined in Section X.M1 of NUREG-2191 and Section 4.3 of NUREG-2192, the effects of the reactor water environment on cumulative usage factor (CUF) must be examined for a set of sample critical components for the plant. This sample set includes the locations identified in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components" (Reference 4.8-46) and additional plant-specific component locations in the reactor coolant pressure boundary if they may be more limiting than those considered in NUREG/CR-6260. These additional limiting locations are identified through an environmental fatigue screening evaluation. The environmentally assisted fatigue (EAF) screening process consisted of two methods. The first method made use of existing fatigue usage values for the ASME Code, Section III components. The second method consisted of the EPRI common basis stress evaluation (CBSE) method for estimating fatigue usage for the ANSI B31.1 piping without fatigue values per EPRI Report 1024995, "Environmentally Assisted Fatigue Screening: Process and Technical Basis for Identifying EAF Limiting Locations" (Reference 4.8-47). The EAF screening evaluation reviewed the CLB fatigue evaluations for all ASME Code, Section III reactor coolant pressure boundary components and ANSI B31.1 piping, including the NUREG/CR-6260 locations, to determine the lead indicator (also referred to as sentinel) locations for EAF.

TLAA Evaluation:

To support subsequent license renewal, calculations were prepared to document the evaluations of environmentally-assisted fatigue for ASME Code, Section III pressure boundary components and piping that contact the reactor coolant, and determine fatigue-sensitive locations for comparison and ranking. These evaluations are for subsequent license renewal purposes and do not amend the existing design reports. The TLAA evaluation is presented separately for ASME Code, Section III and ANSI B31.1 components and piping. Discussion of the screening approaches used for the ASME Code, Section III Components and ANSI B31.1 piping are provided below due to slight differences in the screening approach used. As a result of the EAF screening evaluation, there were other locations found that could potentially be more limiting than the NUREG/CR-6260 locations (see WCAP-18341-P, SIA 1600274.305, Revision ~~2~~3, "Selection of Sentinel Locations Based on Environmentally Assisted Fatigue Screening" (Reference 4.8-48) and SIA FP-SPS-401, Revision 1, "Surry Subsequent License Renewal Fatigue Management Accumulation Report," (Reference 4.8-49). A consolidated tabulation for ASME Code, Section III pressure boundary components and piping is presented for the sentinel locations in Table 4.3.4-1.

TLAA Evaluation:

Method of Evaluation-Scope

The cranes potentially subject to TLAA are those subject to NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants" (Reference 4.8-66). As documented in UFSAR Section 9B.2, the following load handling systems are consistent with NUREG-0612:

- Containment polar cranes
- Containment annulus monorail
- Containment jib cranes
- Fuel building motor-driven platform
- Auxiliary building 10-ton monorail (27 foot level)
- Auxiliary building 5-ton monorail (13 foot level)
- Residual heat removal pump motor lifting lugs
- Spent fuel crane

The following NUREG-0612 load handling systems have been designed to or evaluated as meeting the requirements of ANSI Standards B30.11-1973, "Monorail Systems and Underhung Cranes" (Reference 4.8-67) and B30.16-1973, "Overhead Hoists" (Reference 4.8-68) or ASME Standard HST-4, "Performance Standard for Overhead Electric Wire Rope Hoists" (Reference 4.8-69). These standards do not specify load cycle limits:

- Containment jib cranes
- Containment annulus monorails
- Auxiliary Building 10-ton monorail (27 foot level)
- Auxiliary Building 5-ton monorail (13 foot level)
- Fuel Building motor-driven platform

<u>The residual heat removal pump motor lifting lugs are anchored to the concrete structure to provide rigging attachments for installation/removal of the residual heat removal pump motors. The lugs are designed for the dead weight of the motors, their attachments, and rigging. The design calculations for these lugs do not specify load cycle limits.</u>

The following NUREG-0612 load handling systems have been evaluated to the load cycle requirements of CMAA Specification 70 or its historical equivalent, Electric Overhead Crane Institute (EOCI) Specification 61, "Specifications for Electric Overhead Traveling Cranes" (Reference 4.8-70):

- Containment polar cranes
- Spent fuel crane

4.7.3 LEAK-BEFORE-BREAK

TLAA Description:

The aging effect identified in this TLAA is thermal aging of CASS material resulting in embrittlement, that is, a decrease in the ductility, impact strength, and fracture toughness and an increase in hardness and tensile strength of the material. This TLAA uses fully-aged fracture toughness properties.

The fatigue crack growth evaluation performed in WCAP-15550-P, Revision ~~1~~2 (Reference 4.8-76) is a defense in depth evaluation to demonstrate that small surface flaws do not become through-wall flaws over the life of the plant. The fatigue crack growth evaluation was based on a generic model with representative design transient and cycles that are applicable to SPS.

10 CFR 50, Appendix A, Criterion 4, allows for the use of leak-before-break (LBB) methodology for excluding the dynamic effects of postulated ruptures in reactor coolant system piping. The fundamental premise of the LBB methodology is that the materials used in nuclear power plant piping are sufficiently tough that even a large through-wall crack would remain stable and would not result in a double-ended pipe rupture.

Updated Final Safety Analysis Report Sections 18.3.5.3 and 14.5.1.2 discuss LBB, which applies only to the reactor coolant system (RCS) primary loop piping.

To maintain the LBB design basis for the plant, the LBB evaluation needed to be performed for an 80-year plant life.

TLAA Evaluation:

WCAP-15550-P (Revision 0), "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as a Structural Design Basis for the Surry Units 1 and 2 Nuclear Power Plants for the License Renewal Program," had demonstrated compliance with LBB technology for the RCS piping for 60-year plant life based on a plant-specific analysis. Subsequently, a LBB evaluation was performed for the MUR power uprate. WCAP-15550-NP (Revision ~~1~~2), "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Surry Units 1 and 2 Nuclear Power Plants for the Subsequent License Renewal Program (80 years) Leak-Before-Break Evaluation" (Reference 4.8-77), performed the evaluation for 80 years. The results of the MUR power uprate analysis are included in WCAP-15550-NP (Revision 1).

The analysis documented the plant-specific geometry, loading, and material properties used in the fracture mechanics evaluation. Mechanical properties were determined at operating temperatures. Since the piping systems include cast austenitic stainless steel, fracture toughness considering thermal aging was determined for each heat of material. Fully aged fracture toughness properties were used for the LBB evaluation. The fully aged condition is applicable for plants operating beyond

15 EFPY for the CF8M materials (elbows for Units 1 and 2). As of January 2017, Units 1 and 2 were operating at 33.78 and 33.69 EFPY, respectively.

The updates performed for WCAP-15550-NP included a recalculation of delta ferrite and fracture toughness properties based on NUREG/CR-4513, "Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems" (Reference 4.8-78). The chemistry data for the fracture mechanics parameters are provided in WCAP-15550-P (Revision 0). Fracture toughness parameters were recalculated using information from NUREG/CR-4513.

Fatigue crack growth rate laws were used from the ASME Code, Section XI, for the ferritic steel and stainless steel. The fatigue crack growth rate laws were all structured for applicability to pressurized water reactor environments, and are still applicable for an 80-year assessment. The current piping loads and stresses are unchanged from WCAP-15550 (Revision 0) and are used in WCAP-15550 (Revision ~~1~~2). The evaluation methodology from Revision 0 was used in Revision ~~1~~2.

The fatigue crack growth analysis used CLB cycles (40-year design cycles). As shown in Table 4.3.1-1, the 40-year design cycles (CLB cycles) are postulated to bound 80 years of plant operations. Therefore, the fatigue crack growth analysis for the LBB analysis has been projected to the end of the period of extended operation.

The analysis provides a fracture mechanics demonstration of reactor coolant system primary loop integrity consistent with the NRC position for exemption from consideration of dynamic effects noted in NUREG-0800, Section 3.6.3, "Leak-Before-Break Evaluation Procedures" (Reference 4.8-79). The analysis justifies the elimination of reactor coolant system primary loop pipe breaks from the structural design basis for the 80-year plant life as follows:

a. Stress corrosion cracking is precluded by use of fracture resistant materials in the piping system and controls on reactor coolant chemistry, temperature, pressure, and flow during normal operation. There is no Alloy 82/182 material present in the welds for reactor coolant system primary loop piping.
b. Water hammer should not occur in the reactor coolant system piping because of system design, testing, and operational considerations.
c. The effects of low and high cycle fatigue on the integrity of the primary piping are negligible.
d. Margin exists between the leak rate of small stable flaws and the capability of the reactor coolant system pressure boundary leakage detection system.
e. Margin exists between the small stable flaw sizes of item (d) and larger stable flaws.
f. Margin exists in the fully-aged material properties to demonstrate stability of the critical flaws after 80 years of operation.

The critical postulated flaw locations are shown to be stable because of the ample margins described in d, e, and f above.

Based on the above, the LBB conditions and all recommended margins are satisfied for the reactor coolant system primary loop piping. It is therefore concluded that dynamic effects of reactor coolant system primary loop pipe breaks need not be considered in the structural design basis for Units 1 and 2 for the 80-year plant life.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The assessment performed in WCAP-15550-P, Revision ~~1~~2 determined that the crack stability results, fracture toughness, and fatigue crack growth results are acceptable for 80 years of plant operation. Therefore, the LBB analysis is projected through the subsequent period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

4.7.4 SPENT FUEL POOL LINER FATIGUE ANALYSIS

TLAA Description:

The spent fuel pool liner located in the Fuel Building is needed to prevent a leak to the environment. A design calculation (Reference 4.8-80) has been identified which documents that the spent fuel pool design meets the general industry criteria of ASME Code, Section III, Subsections NB-3222.2, NB-3222.4, and NB-3228.5, 2010. (Reference 4.8-81) The calculation includes a fatigue analysis to add a further degree of confidence.

TLAA Evaluation:

As discussed in UFSAR Section 9.5.1, the fuel pool water temperature is continuously indicated in the control room, and an alarm in the control room alerts the operator prior to this temperature reaching 140°F.

The fuel pool cooling system has the capability to:

1. Maintain the temperature of the fuel pool water below 140°F during a normal core offload condition commencing 100 hours after shutdown. A normal core offload condition is a planned offload of up to a full core. The most limiting condition for normal core offload is a full core offload following refueling of the other unit.
2. Maintain the temperature of the fuel pool water below 170°F during an abnormal core offload condition commencing 100 hours after shutdown. An abnormal core offload is an unplanned offload of up to a full core. The most limiting condition for an abnormal core offload is an unplanned full core offload following back-to-back refuelings of both units

The spent fuel pool liner was designed for three conditions:

Condition 1: Normal core offload, maximum temperature = 140°F

Condition 2: Abnormal core offload, maximum temperature = 170°F

Condition 3: Faulted Condition, maximum temperature = 212°F

4.7.5 PIPING SUBSURFACE FLAW EVALUATIONS

TLAA Description:

Piping subsurface flaw evaluations are discussed in UFSAR, Section 18.3.5.5. Initial license renewal identified calculations that address piping subsurface indications (detected by inspections that were conducted during original plant construction, and that were performed in accordance with ASME Code, Section XI, which provided the acceptance criteria for various flaw orientations, locations, and sizes). The calculations determined the number of thermal cycles required for the flaws to reach an unacceptable size. This TLAA evaluates the effects of fatigue on previously disclosed subsurface flaws to ensure operational margin through the subsequent period of extended operation.

TLAA Evaluation:

The piping subsurface calculations were reassessed for 80 years of operation. The 80-year calculations described in LTR-PAFM-17-14, "Subject: Surry Units 1 and 2 Piping Subsurface Flaw Evaluation for 80 Years of Service, Subsequent License Renewal" (Reference 4.8-83), were based on the fatigue crack growth equations of ASME Code, Section XI, Appendix A and Appendix C.

The analysis considered three topics which were updates to stresses, changes in stress intensity factor calculations, and changes in fatigue crack growth rates since the original analysis performed in 1972. Stress intensity factors were updated, where necessary. The piping subsurface indication allowable and estimated cycles are depicted in Table 4.7.5-1.

Table 4.7.5-1 Piping Subsurface Indication Allowable and Estimated Cycles

Item	Line	Stresses (psi)	Stress Intensity Factor (K_I)	Allowable Cycles[1]	Estimated Cycles for 80 Years[3]
1 & 3	~~Fire Protection~~Fuel Pool Cooling	15,908	recalculated[2]	6,255	~~40~~165
2	Feedwater (slag inclusion)	11,391	original	422,874	~~120~~165
4	Feedwater (backing ring)	5,914	original	3,886,003	~~120~~165
5	Seismic I Category Piping	27,700	recalculated[2]	70,390	~~120~~165

1. All Allowable Cycles to reach maximum flaw size were reduced from original analysis.
2. The latest stress intensity factor used in the industry based on API-579-1, "Fitness-For-Service," (Reference 4.8-84) was applied to the evaluation.
3. Cycles were conservatively estimated using the 80-year projected number of heatups to bound the projected number of cycles for all the listed piping. Table 4.3.1-1 provides the 80-Year Transient Cycle Projections. These cycles bound the estimated cycles for the fuel pool cooling as outlined in Table 4.3.3-1.

The calculated allowable cycles were all well above the estimated cycles that are expected to occur for these lines in an 80-year life (allowable cycles are ~~150~~37 times greater than estimated cycles for Items 1 & 3, and at least ~~500~~426 times greater than the estimated cycles for Items 2, 4 and 5). Therefore, there is no need for any future repair, replacements, or re-evaluations of these particular indications and lines discussed.

TLAA Disposition: 10 CFR 54.21(c)(1)(ii)

The piping subsurface flaws detected during original plant construction have been re-evaluated for 80-year life and shown to have allowable cycles well above the estimated cycles expected for the piping components of interest and are therefore projected through the subsequent period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

4.7.6 REACTOR COOLANT PUMP CODE CASE N-481

TLAA Description:

The SPS reactor coolant pumps (RCPs) are model 93A with SA-351, Grade CF-8 pump casings. Periodic volumetric inspections of the welds of the reactor coolant system (RCS) primary loop pump casings of commercial nuclear power plants were specified by ASME Code, Section XI. The inspections result in large radiation exposure (man-rem), which is a personnel safety concern. Since the pump casings were inspected prior to being placed in service, and no significant mechanisms exist for crack initiation and propagation, it has been concluded that the inservice volumetric inspection can be replaced with an acceptable alternate inspection. In recognition of this, ASME Code Case N-481, "Alternative Examination Requirements for Cast Austenitic Pump Casings" (Reference 4.8-85), provides an alternative to the volumetric inspection requirement. ASME Code Case N-481 allows the replacement of volumetric examinations of RCS primary loop pump casings with fracture mechanics-based integrity evaluations (Item (d) of the code case) supplemented by specific visual examinations.

The initial evaluation included in WCAP-13045, "Compliance to ASME Code Case N-481of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply System" (Reference 4.8-86), has been updated to validate saturated fracture toughness values are used for assessment of the integrity of the pump casing through the subsequent period of extended operation. Validation of this fracture mechanics evaluation was specified in ASME Code Case N-481 as a condition to conduct visual examinations in lieu of the volumetric inspections specified in ASME Code, Section XI.

TLAAs related to ASME Code Case N-481 have been identified: thermal aging of cast austenitic stainless steel (CASS) and its consequence on fatigue crack growth. ASME Code Case N-481 is discussed in UFSAR, Section 18.3.5.6.

4.8-45 NRC Letter to Stoddard, "Surry Power Station, Units 1 and 2 - Revised License Renewal Commitment Pressurizer Surge Line Inspection Frequency (EP ID L-2017-LR0-0078)," June 29, 2018. (ML18166A329)

4.8-46 NUREG/CR-6260 (INEL-95/0045), "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," March 1995. (ML031480219)

4.8-47 EPRI Report 1024995, "Environmentally Assisted Fatigue Screening: Process and Technical Basis for Identifying EAF Limiting Locations," 2012.

4.8-48 SIA 1600274.305, Revision ~~2~~3, "Selection of Sentinel Locations Based on Environmentally Assisted Fatigue Screening," ~~September 20, 2018~~.

4.8-49 SIA Report FP-SPS-401, Revision 1, "Surry Subsequent License Renewal Fatigue Management Accumulation Report," September 2018.

4.8-50 NUREG/CR-6909 (ANL-12/60), Revision 0, "Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials, Final Report," February 2007. (ML070660620)

4.8-51 NUREG/CR-6909, Revision 1 (Pre-Publication Version), "Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials," March 2018.

4.8-52 NUREG/CR-6909 (ANL-12/60), Draft Revision 1, "Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials Draft Report for Comment," March 2014. (ML14087A068)

4.8-53 EPRI Technical Report TR3002000505, Volume 1, Revision 7, "Pressurized Water Reactor Primary Water Chemistry Guidelines," April 2014.

4.8-54 NRC Bulletin 88-08, Supplement 2, "Thermal Stresses in Piping Connected to Reactor Coolant System," August 4, 1988. (ML031220144)

4.8-55 ASME Code Case N-809, "Reference Fatigue Crack Growth Rate Curves for Austenitic Stainless Steels in Pressurized Water Reactor Environments, Section XI, Division 1, ASME International," June 23, 2015.

4.8-56 WCAP-18339-P (Proprietary), Revision 0, "Surry Units 1 and 2 ASME Section XI Appendix L Flaw Tolerance Evaluation for Safety Injection, Residual Heat Removal, Pressurizer Spray, Charging and Accumulator Lines," August 2018.

4.8-57 SIA Report Number 1601007.401 (Proprietary), Revision 0, "Flaw Tolerance Evaluation of the Surry Unit 1 and 2 Hot Leg Surge Line Nozzles Using ASME Code Section XI, Appendix L," September 2017.

4.8-58 Westinghouse Calculation CN-PAFM-03-46, Revision 1, "Surry 12" Accumulator Nozzle Fatigue Analysis with Environmental Effects," March 30, 2009.

4.8-59 CN-PAFM-03-47, Revision 1, "Surry 3" Charging Nozzle Fatigue Analysis with Environmental Effects," March 30, 2009.

4.8-60 NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels," April 1999. (ML031480394)

4.8-61 WCAP-16990-P (Proprietary), Revision 0, "Surry Units 1 and 2 Measurement Uncertainty Recapture Power Uprate Project Engineering Report," May 2010.

4.8-62 Inspection and Enforcement Bulletin (IEB) 79-01B, "Environmental Qualification of Class 1E Equipment." (ML080310648)

4.8-63 IEEE Standard 323-1974, "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations." (ML032200206)

4.8-64 11448-EA-62, Revision 0, Add. 00C, "Reactor Containment Liner Fatigue Evaluation for 80-Year Plant Life."

4.8-65 Crane Manufacturers Association of America Specification 70, 1975.

4.8-66 NUREG-0612, "Control of Heavy Loads at Nuclear power Plants," July 1980. (ML070250180)

4.8-67 ANSI Standard B30.11-1973, "Monorail Systems and Underhung Cranes."

4.8-68 ANSI Standard B30.16-1973, "Overhead Hoists."

4.8-69 ASME Standard HST-4, "Performance Standard for Overhead Electric Wire Rope Hoists."

4.8-70 Electric Overhead Crane Institute (EOCI) Specification 61 for Electric Overhead Traveling Cranes.

4.8-71 NRC Generic Letter 81-07, "Control of Heavy Loads."

4.8-72 WCAP-14535A, "Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination," November 1996.

4.8-73 NRC Letter, "Surry Power Station, Units 1 and 2 - Issuance of Amendments to Extend the Inspection Interval for Reactor Coolant Pump Flywheels (TAC Nos. MC4215 and MC4216)," June 21, 2005. (ML051640591)

4.8-74 WCAP-15666-A, Revision 1, "Extension of Reactor Coolant Pump Motor Flywheel Examination," October 2003.

4.8-75 PWROG-17011-NP, Revision ~~1~~2, "Update for Subsequent License Renewal: WCAP-14535A, 'Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination' and WCAP-15666-A, 'Extension of Reactor Coolant Pump Motor Flywheel Examination,'" ~~May 2018.~~January, 2019.

4.8-76 WCAP-15550-P (Proprietary), Revision ~~1~~2, “Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Surry Units 1 and 2 Nuclear Power Plants for the Subsequent License Renewal Program (80 years) Leak-Before-Break Evaluation,” ~~June 2017~~March 2019.

4.8-77 WCAP-15550-NP, Revision ~~1~~2, “Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Surry Units 1 and 2 Nuclear Power Plants for the Subsequent License Renewal Program (80 years) Leak-Before-Break Evaluation,” ~~June 2017~~March 2019.

4.8-78 NUREG/CR-4513, Revision 2, “Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems,” May 2016. (ML16145A082)

4.8-79 NUREG-0800, Standard Review Plan, Revision 1, Section 3.6.3, “Leak-Before-Break Evaluation Procedures,” March 2007. (ML03600396)

4.8-80 CE-1272, Revision 0, Add. 00B, “Fuel Pool Liner Fatigue Evaluation for 80 Years Plant Life.”

4.8-81 ASME Boiler and Pressure Vessel Code, Section III, Subsections NB-3222.2, NB-3222.4, and NB-3228.5, 2010.

4.8-82 CE-1272, Revision 0, “Analysis of Surry Fuel Pool Liner at 212 Degrees Fahrenheit.”

4.8-83 LTR-PAFM-17-14 Revision ~~0~~2, “Subject: Surry Units 1 and 2 Piping Subsurface Flaw Evaluation for 80 Years of Service, Subsequent License Renewal,” ~~April 4, 2017~~March 20, 2019.

4.8-84 American Petroleum Institute Standard, API-579-1, “Fitness-For-Service”.

4.8-85 ASME Code Case N-481, “Alternative Examination Requirements for Cast Austenitic Pump Casings, Section XI, Division 1,” March 5, 1990.

4.8-86 WCAP-13045 (Proprietary), “Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply System,” September 1991.

4.8-87 WCAP-13044 (Proprietary Class 3), “Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply System,” September 1991.

4.8-88 PWROG-17033-NP, Revision 1, "Update for Subsequent License Renewal: WCAP-13045, 'Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems,'" June 2018.

4.8-89 CN-AMLRS-10-3 (Proprietary), Revision 0, “Implementation of WCAP-16168-NP-A, Revision 2, for Surry Units 1 and 2,” July 29, 2010.

4.8-90 WCAP-15338-A, “A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants,” October 2002.

A1.9 BOLTING INTEGRITY

The *Bolting Integrity* program is an existing condition monitoring program that manages cracking, aging by performing periodic visual inspections for indications of cracking, loss of material due to general, pitting, and crevice corrosion, microbiologically-influenced corrosion, wear, and loss of preload as evidenced by leakage ~~of~~ for safety-related and non safety-related closure bolting ~~for~~ on pressure-retaining components within the scope of subsequent license renewal.

The program refers to NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants". NUREG-1339 includes guidance from EPRI report NP-5067, "Good Bolting Practices Volume 1 (Large Bolt Manual)," and from EPRI report NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants".

The listing for EPRI NP-5769 mentions an exception noted in NUREG-1339 for safety-related bolting. That exception is applicable for bolting used in pressure-retaining applications, and indicates that experimentally–verified fastener material properties and fracture mechanics evaluations should be used to ensure that safety-related fasteners are unlikely to be susceptible to stress corrosion cracking. EPRI Report 1015336, "Nuclear Maintenance Application Center: Bolted Joint Fundamentals," is applicable for the Bolting Integrity program, and states that applicable material properties should be confirmed with the fastener manufacturer. EPRI Report 1015336 includes guidance for preventing or mitigating stress corrosion cracking by the proper selection of bolting. Table B-1 of EPRI Report 1015336 lists appropriate bolting, and is a reference for the bolting design standard at SPS.

The program includes guidance provided by EPRI reports 1015336, "Nuclear Maintenance Application Center: Bolted Joint Fundamentals," and 1015337, "Nuclear Maintenance Application Center: Assembling Gasketed Flanged Bolted Joints," for assembling bolted connections, and for performing visual examinations of pressure-retaining closure bolting. Preventive measures to preclude or mitigate cracking and loss of preload include proper selections of bolting material and lubricant, and proper application of preload. The absence of high-strength pressure-retaining closure bolting precludes the need for volumetric inspections.

The program addresses management of age-related degradation for applicable submerged bolting, and for piping systems that contain compressed air, hydrogen gas, nitrogen gas, and carbon dioxide. ~~Aging management is not required for piping in nitrogen and hydrogen systems due to the absence of in-scope pressure retaining closure bolting.~~

The *ASME Section XI Inservice Inspections, Subsections IWB, IWC, AND IWD* program (Section A1.1) includes inspections of closure bolting within the scope of ASME Code, Section XI, and supplements this *Bolting Integrity* program. The reactor vessel closure head studs are addressed in the *Reactor Head Closure Stud Bolting* program (A1.3). The following aging management programs for SPS manage aging effects associated with safety-related and non safety-related structural bolting:

- *ASME Section XI, Subsection IWE* program (Section A1.29)
- *ASME Section XI, Subsection IWF* program (Section A1.31)
- *Structures Monitoring* program (Section A1.34)
- *Inspection of Water-Control Structures Associated With Nuclear Power Plants* program (Section A1.35)
- *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program (Section A1.13)

The *External Surfaces Monitoring of Mechanical Components* program (Section A1.23) describes the inspections for non-ASME pressure-retaining bolting.

A1.10 STEAM GENERATORS

The *Steam Generators* program is an existing condition monitoring program that manages the aging effects of cracking, loss of material (e.g., wall thinning), and reduction of heat transfer for the steam generators. The scope of the program includes primary-side components (e.g., U- tubes [tubes], plugs, sleeves, channel head divider plate, channel head, tubesheet, etc.), and secondary-side components that are contained within the steam generator. The program uses volumetric inspections for the tubes, and visual inspections for the other primary-side and secondary-side components. The visual inspections of the primary-side components listed above are performed in accordance with the Degradation Assessment (DA) that is prepared as each steam generator is scheduled for examination. Tube-to-tubesheet welds do not require aging management because the H* alternate repair criteria have been permanently approved to eliminate those hot-leg and cold-leg welds as reactor coolant pressure boundaries.

Provisions in the *Steam Generators* program address reporting criteria, inspection scope and frequency, assessments, plugging criteria, and water chemistry monitoring to maintain consistency with established requirements. NEI 97-06, Revision 3, "Steam Generator Program Guidelines" and associated EPRI guidelines provide a generic industry program to implement Technical Specifications.

As stated in the steam generator DA, tubing and primary-side inspections typically are performed every other refueling outage for each steam generator, thus satisfying the guidance for visual inspections to be performed at least every 72 effective full power months or every third refueling outage, whichever results in more frequent inspections.

The *Steam Generators* program includes preventive measures to mitigate aging related to corrosion phenomena through foreign material exclusion as a means to inhibit tube degradation visual inspections, flow testing, and flushes consistent with provisions of the 2011 Edition of National Fire Protection Association (NFPA) 25. Testing of sprinklers that have been in place for 50 years is performed consistent with NFPA 25, 2011 Edition. With exception of two locations, portions of the water-based fire protection system that have been wetted but are normally dry have been confirmed to drain and are not subjected to augmented testing and inspections.

The water-based fire protection system is normally maintained at required operating pressure and is monitored such that loss of system pressure is detected and corrective actions initiated. Piping wall thickness measurements are conducted when visual inspections detect surface irregularities indicative of unexpected levels of degradation. When the presence of organic or inorganic material sufficient to obstruct piping or sprinklers is detected, the material is removed and the source is detected and corrected. Non-code inspections and tests follow site procedures that include inspection parameters for items such as lighting, distance offset, presence of protective coatings, and cleaning processes that ensure an adequate examination.

A1.17 OUTDOOR AND LARGE ATMOSPHERIC METALLIC STORAGE TANKS

The *Outdoor and Large Atmospheric Metallic Storage Tanks* program is an existing condition monitoring program that manages the effects of loss of material and cracking on the outside and inside surfaces of aboveground metallic tanks constructed on concrete or soil. This program is a condition monitoring program that manages aging effects associated with outdoor tanks with internal pressures approximating atmospheric pressure including the refueling water storage tanks (RWSTs), refueling water chemical addition tanks (CATs), emergency condensate storage tanks (ECSTs), and the emergency condensate makeup tanks (ECMTs). This program also manages aging of the fire protection/domestic water storage tanks (FWSTs) bottom surfaces exposed to soil. The program includes preventive measures to mitigate corrosion by protecting the external surfaces of steel components per standard industry practice. The RWSTs are insulated and rest on a concrete foundation covered with an oil sand cushion. Caulking is used at the concrete-component interface of the RWSTs. The ECSTs and ECMTs are internally coated and protected by concrete missile barriers. Weep holes, located around the circumference of the ECSTs where the concrete missile shield meets the concrete foundation, allow drainage of leakage or condensation to the outside perimeter of the ECSTs. The weep holes will be inspected for water leakage once each refueling cycle. The CATs are skirt supported and insulated with sprayed-on rigid polyurethane foam.

The program manages loss of material on tank internal bare metal surfaces by conducting visual inspections. Surface exams of external tank surfaces are conducted to detect cracking on the stainless steel tanks. Inspections of RWST caulking are supplemented with physical manipulation. Thickness measurements of the tanks bottoms are conducted to ensure that significant degradation is not occurring. The external surfaces of insulated tanks are periodically sampling-based inspected. Inspections not conducted in accordance with ASME Code Section XI requirements are conducted in accordance with plant-specific procedures that include inspection parameters such as lighting, distance, offset, and surface conditions.

The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (A1.28) will manage the internally coated surfaces of the ECSTs and ECMTs. Internal surfaces of the RWSTs and CATs will be managed by the *One-Time Inspection* program (A1.20). Tank reinforced concrete foundations and the reinforced concrete missile barrier of the ECSTs and ECMTs will be managed by the *Structures Monitoring* program (A1.34).

A1.18 FUEL OIL CHEMISTRY

The *Fuel Oil Chemistry* program is an existing mitigative and condition monitoring and preventive program that manages loss of material <u>and reduction of heat transfer</u> from tanks, piping, and components in a fuel oil environment. The program includes activities which provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of subsequent license renewal.

The fuel oil tanks within the scope of subsequent license renewal are maintained by monitoring and controlling fuel oil contaminants in accordance with ~~Technical Specifications,~~ the Technical Requirements Manual~~,~~ and ASTM standards <u>such as ASTM D 975, D 1796, D 6217, and D 4057</u>. Fuel oil sampling and analysis is performed in accordance with approved procedures for new fuel oil and stored fuel oil.

Fuel oil tanks are periodically drained of water and accumulated sediment, cleaned, and internally inspected when accessible. These activities effectively manage the effects of aging by maintaining potentially harmful contaminants at low concentrations. Where internal cleaning and inspection are not physically possible, bottom thickness measurements of inaccessible tanks are performed in lieu of cleaning and internal inspection. Tanks that cannot be cleaned and internally inspected, and are physically inaccessible for bottom thickness measurements, are monitored for leakage consistent with the current licensing basis.

A1.19 REACTOR VESSEL MATERIAL SURVEILLANCE

The *Reactor Vessel Material Surveillance* program is an existing condition monitoring program that manages reduction of fracture toughness of the ferritic reactor vessel beltline materials, in accordance with the version of ASTM E-185 available and used during fabrication of the reactor vessels. The program provides sufficient material to monitor reduction of fracture toughness due to neutron irradiation embrittlement until the end of the subsequent period of extended operation, and determine the need for operating restrictions on the irradiation temperature (i.e., cold leg operating temperature), neutron spectrum, and neutron fluence.

A1.24 FLUX THIMBLE TUBE INSPECTION

The *Flux Thimble Tube Inspection* program is an existing condition monitoring program that manages loss of material due to wear by inspecting for the thinning of flux thimble tube walls. Flux thimble tubes provide a path for the in-core neutron flux monitoring system detectors and forms part of the reactor coolant system pressure boundary. Flux thimble tubes are subject to loss of material at certain locations in the reactor vessel (RV) where flow-induced fretting causes wear at discontinuities in the path from the RV instrument nozzle to the fuel assembly instrument guide tube. The thimble tube design is a double-walled, asymmetrical configuration to accommodate thermocouple leads located in the annulus between the inner and outer flux thimble tubes. The outer tube is the component that is most susceptible to wear due to its contact with the discontinuities. The inner tube through which the incore detector travels is the reactor coolant system pressure boundary. The double wall design significantly reduces the potential for wear of the inner tube pressure boundary. Periodic eddy current examinations are performed to confirm the integrity of the inner flux thimble tube, and are consistent with the recommendations of NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors."

A1.25 INSPECTION OF INTERNAL SURFACES IN MISCELLANEOUS PIPING AND DUCTING COMPONENTS

The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program is an existing condition monitoring program that manages loss of material, cracking, reduction of heat transfer, and flow blockage of metallic components. The program also manages hardening or loss of strength, loss of material, cracking or blistering, and flow blockage of polymeric components. This program consists of visual inspections of all accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components, and other components exposed to air, condensation, diesel exhaust, fuel oil, lubricating oil, and any water environment. Aging effects associated with items (except for elastomers) within the scope of the *Open-Cycle Cooling Water System* program (A1.11), *Closed Treated Water Systems* program (A1.12), and *Fire Water System* program (A1.16) are not managed by this program. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength is used to augment the visual examinations conducted under this program.

Surface examinations or ASME Code, Section XI, visual examinations (VT-1) are conducted to detect cracking of stainless steel, aluminum, ~~and~~ copper alloy (>15% Zn), and Grade 2 titanium components.

The internal inspections are performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. At a minimum, in each 10-year period during the subsequent period of extended operation, a representative sample of 20% of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of nineteen components per population at each unit is inspected. Where practical, the inspections focus on the bounding or lead components most susceptible to aging because of time in service and severity of operating conditions. Opportunistic inspections continue in each period, even if the minimum number of inspections has been conducted.

Inspections are performed by personnel qualified in accordance with procedures and programs to perform the specified task. Inspections within the scope of the ASME Code will follow procedures consistent with the ASME Code. Non-ASME Code inspection procedures include requirements for items such as lighting, distance, offset, and surface conditions.

Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the subsequent period of extended operation. Qualitative acceptance criteria are clear enough to reasonably ensure a singular decision is derived based on observed conditions.

A1.26 LUBRICATING OIL ANALYSIS

The *Lubricating Oil Analysis* program is an existing preventive program that ensures that loss of material and reduction of heat transfer is not occurring by maintaining the quality of the lubricating oil or hydraulic oil. The program ensures that contaminants (primarily water and particulates) are within acceptable limits. Testing activities include sampling and analysis of lubricating oil for contaminants. Oil testing that indicates the presence of water results in the initiation of corrective action that may include evaluating for in-leakage.

A1.27 BURIED AND UNDERGROUND PIPING AND TANKS

The *Buried and Underground Piping and Tanks* program is an existing condition monitoring program that manages loss of material, blistering, and cracking on external surfaces of components in soil or underground environments within the scope of subsequent license renewal through preventive and mitigative actions. The program addresses piping and tanks composed of steel, stainless steel, copper alloys, fiberglass reinforced plastic, and concrete. Depending on the material, preventive and mitigative techniques include external coatings, cathodic protection (CP), and the quality of backfill. Direct visual inspection quantities for buried components are planned using procedural categorization criteria. Transitioning to a higher number of inspections than originally planned is based on the effectiveness of the preventive and mitigative actions. Also, depending on the material, inspection activities include electrochemical verification of the effectiveness of CP, nondestructive evaluation of pipe or tank wall thicknesses, performance monitoring of fire mains, and visual inspections of the pipe from the exterior.

The buried carbon steel piping of the fuel oil system for emergency electrical power system is the only buried piping that is protected by an active CP system. Monthly periodic inspections confirm CP system availability and annual CP surveys are conducted to assess the effectiveness of the CP system. ~~For steel components, the CP effectiveness acceptance criterion is -850 mV instant-off.~~ For steel components, where the acceptance criteria for the effectiveness of the cathodic protection is other than -850 mV instant off, loss of material rates are measured.

The balance of piping and tanks within the scope of subsequent license renewal are not provided with CP. Soil sampling and testing is performed during each excavation and a station-wide soil survey is also performed once in each 10-year period to confirm that the soil environment of components within the scope of subsequent license renewal is not corrosive for the installed material types.

Inspections are conducted by qualified individuals. Where the coatings, backfill or the condition of exposed piping does not meet acceptance criteria such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is extrapolated to the end of the subsequent period of extended operation, the sample size is increased.

As an alternative to performing visual inspections of the buried fire protection system components, monitoring the activity of the jockey pump is performed by the *Fire Water System* program (A1.16).

A1.28 INTERNAL COATINGS/LININGS FOR IN-SCOPE PIPING, PIPING COMPONENTS, HEAT EXCHANGERS, AND TANKS

The *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program is an existing condition monitoring program that manages loss of coating integrity of the internal coatings/linings of the in-scope components, exposed to closed-cycle cooling water, raw water, treated water, treated borated water, ~~and~~ waste water, and air-dry environments, that can lead to loss of base material or downstream effects such as reduction in flow, reduction in pressure or reduction of heat transfer when coatings/linings become debris.

Periodic visual inspections are conducted of each coating/lining material and environment combinations applied to the internal surfaces of in-scope piping and components where loss of coating or lining integrity could impact the components or downstream component's intended function(s).

For tanks, ~~and~~ heat exchangers and piping, all accessible surfaces are inspected. ~~Piping inspections are sample based.~~ The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings are conducted in accordance with ASTM International Standards endorsed in RG 1.54, "Service Level I, II and II Protective Coatings Applied to Nuclear Power Plants," including guidance from the staff associated with a particular standard. For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces. Peeling and delamination is not acceptable. Blisters are evaluated by a coatings specialist. Blisters are limited to a few intact small blisters that are completely surrounded by sound material and with the size and frequency not increasing between inspections. Minor cracks in cementitious coatings are acceptable provided there is no evidence of debonding. All other degraded conditions are evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, the coating can be removed or physical testing is performed where physically possible (i.e., sufficient room to conduct testing) in conjunction with repair or replacement of the coating/lining.

A1.33 MASONRY WALLS

The *Masonry Walls* program is an existing condition monitoring program that is implemented as part of the *Structures Monitoring* program (A1.34) and manages loss of material, cracking, and loss of material (spalling and scaling) that could impact the intended function of the masonry walls.

The *Masonry Walls* program consists of inspections, consistent with Inspection and Enforcement Bulletin (IEB) 80-11 and plant-specific monitoring proposed by Information Notice (IN) 87-67, for managing shrinkage, separation, gaps, loss of material and cracking of masonry walls such that the evaluation basis is not invalidated and intended functions are maintained. The inspections of the masonry walls within the scope of subsequent license renewal are conducted by qualified personnel at a frequency not to exceed five years.

A1.34 STRUCTURES MONITORING

The *Structures Monitoring* program is an existing condition monitoring program that monitors the condition of structures and structural supports that are within the scope of subsequent license renewal to manage the following aging effects:

- Cracking
- Cracking and distortion
- Cracking, loss of material
- Cracking, loss of bond, and loss of material (spalling, scaling)
- Increase in porosity and permeability, cracking, loss of material (spalling, scaling)
- Loss of material
- Loss of material, change in material properties
- Loss of material (spalling, scaling) and cracking
- Loss of mechanical function
- Loss of preload
- Loss of sealing
- Reduction in concrete anchor capacity
- Reduction of foundation strength and cracking
- Reduction or loss of isolation function

This program consists of periodic visual inspection and monitoring the condition of concrete and steel structures, structural components, component supports, and structural commodities to ensure that aging degradation (such as those described in ACI 349.3R, ACI 201.1R, and other documents) will be detected, the extent of degradation determined and evaluated, and corrective actions taken prior to loss of intended functions. Inspections also include seismic joint fillers, elastomeric materials; and steel edge supports and steel bracings associated with masonry walls, and periodic evaluation of groundwater chemistry and opportunistic inspections for the condition of below grade concrete. Quantitative results (measurements) and qualitative information from periodic inspections are trended with photographs and surveys for the type, severity, extent, and progression of degradation. The acceptance criteria are derived from applicable consensus codes and standards. For concrete structures, the program includes personnel qualifications and quantitative acceptance criteria of ACI 349.3R-02, "Evaluation of Existing Nuclear Safety-Related Concrete Structures." The inspection of structural components, including masonry walls and water-control structures, are performed at intervals not to exceed five years, except for wooden poles, which are inspected on a 10-year frequency.

Qualified inspectors identify changes that could be indicative of Alkali-Silica Reaction (ASR). If indications of ASR development are identified, the evaluation considers the potential for ASR development in concrete that is within the scope of the *Structures Monitoring* program (A1.34), the *ASME Section XI, Subsection IWL* program (A1.30), or the *Inspection of Water-Control Structures Associated With Nuclear Power Plants* program (A1.35).

ASME Code, Section XI, visual examinations (VT-1) are conducted to detect cracking of stainless steel and aluminum components.

A1.36 PROTECTIVE COATING MONITORING AND MAINTENANCE

The *Protective Coating Monitoring and Maintenance* program is an existing mitigative and condition monitoring program that manages loss of coating integrity of Service Level I coatings inside Containment. ~~The program manages coating system selection, application, visual inspections, assessments, repairs, and maintenance of Service Level I protective coatings as defined in~~ The program maintains and monitors the aging of Service Level 1 coatings consistent with RG 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants".

Maintenance of Service Level I coatings applied to carbon steel and concrete surfaces inside Containment (e.g., steel liner, structural steel, supports, penetrations, and concrete walls and floors) will serve to prevent or minimize the loss of material of carbon steel components due to corrosion and aids in decontamination, but these coatings are not credited for managing the effects of corrosion for the carbon steel containment liner and components. This program ensures that the Service Level I coatings maintain adhesion so as to not affect the intended function of the emergency core cooling systems (ECCS) suction strainers.

The program also provides controls over the amount of unqualified coatings. Unqualified coating may fail in a way to affect the intended function of the ECCS suction strainers. Therefore, the quantity of degraded and unqualified coating is controlled and assessed periodically to ensure that the amount of unqualified coating in the primary containment is kept within acceptable design limits to support the post-accident operability of the ECCS.

A1.37 ELECTRICAL INSULATION FOR ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

The *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is an existing condition monitoring program that manages the aging effect of reduced electrical insulation resistance of the accessible electrical cable and connection insulation material subject to an adverse localized environment.

The program performs a plant walkdown of in-scope structures to visually inspect for accessible cables and connections located in an adverse localized environment. If an adverse localized environment is observed, accessible electrical cables and connections installed within that environment will be visually inspected for the aging mechanisms associated with jacket surface and connection covering anomalies, such as embrittlement, discoloration, cracking, melting, swelling or surface contamination. These anomalies may indicate signs of reduced electrical insulation resistance.

A review of previously identified and mitigated adverse localized environments cumulative aging effects applicable to in-scope cable and connection electrical insulation will be performed.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
7	*PWR Vessel Internals* program	15. Procedures will be revised to require visual examinations (EVT-1), and will include associated acceptance criteria, for 100% of one side of the accessible surfaces of the core barrel lower girth weld and ¾" of adjacent base metal (minimum 50% examination coverage). (Primary component) 16. Procedures will be revised for contingency tasks to inspect the following expansion components if necessitated by relevant indications being found for associated primary components, and will include associated acceptance criteria: a. Core barrel upper, middle, and lower axial welds (100% of weld length – 50% examination coverage; EVT-1) b. Core barrel upper girth weld (100% of weld length – 50% examination coverage; EVT-1) c. Core barrel lower flange weld (100% of weld length – 50% examination coverage; EVT-1) d. Lower support forging (25% of bottom surface; VT-3) e. Upper core plate (25% of accessible surfaces; VT-3) 17. A procedure for visual examinations will be revised to identify the examiner qualifications which are applicable for EVT-1 examinations.	B2.1.7	Program, accounting for the impacts of a gap analysis, will be implemented 6 months prior to the subsequent period of extended operation, or alternatively, a plant-specific program may be implemented 6 months prior to the subsequent period of extended operation.
8	*Flow-Accelerated Corrosion* program	The *Flow-Accelerated Corrosion* program is an existing condition monitoring program that will be enhanced as follows: 1. ~~Procedures will be revised to include a re-evaluation of~~An engineering evaluation will be performed for systems ~~currently~~ that have been excluded from the FAC program due to no flow or infrequently used lines with a total operating and testing time that is less than 2% of the plant operating time. ~~to ensure that an adequate basis exists to justify continuing this exclusion.~~ The purpose of the engineering evaluation is to confirm the scope of components that will qualify for the exclusion being extended into the subsequent period of extended operation. The engineering evaluation and modeling changes for the FAC program will be completed prior to entering the subsequent period of extended operation.(Revised Change Notice 2)	B2.1.8	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
16	*Fire Water System* program	The *Fire Water System* program is an existing condition monitoring program that will be enhanced as follows: ~~1. Procedures inspection guidance will be revised to require replacement of any sprinkler that shows any of the following: leakage, corrosion, physical damage, loading, painting unless painted by the sprinkler manufacturer, or incorrect orientation. Sprinklers at the following locations will be added to the test scope: The Radwaste Facility, Auxiliary Boiler, Maintenance Building, Condensate Polishing Building, Laundry Building, and Machine Shop Building.~~ (Completed Change Notice 1) 2. Prior to 50 years in service, sprinkler heads will be submitted for field-service testing by a recognized testing laboratory consistent with NFPA 25, 2011 Edition, Section 5.3.1. Additional representative samples will be field-service tested every 10 years thereafter to ensure signs of aging are detected in a timely manner. For wet pipe sprinkler systems, a one-time test of sprinklers that have been exposed to water including the sample size, sample selection criteria, and minimum time in service of tested sprinklers will be performed. At each unit, a sample of 3% or a maximum of ten sprinklers with no more than four sprinklers per structure shall be tested. Testing is based on a minimum time in service of fifty years and severity of operating conditions for each population. (Revised Change Notice 2) 3. Procedures will be revised to specify: a. Standpipe and system flow tests for hose stations at the hydraulically most limiting locations for each zone of the system on a five year interval to demonstrate the capability to provide the design pressure at required flow. b. Acceptance criteria for wet pipe main drain tests. Flowing pressures from test to test will be monitored to determine if there is a 10% reduction in full flow pressure when compared to previously performed tests. The Corrective Action Program will determine the cause and necessary corrective action. c. If a flow test or a main drain test does not meet acceptance criteria due to current or projected degradation additional tests are conducted. The number of increased tests is determined in accordance with the corrective action process; however, there are no fewer than two additional tests for each test that did not meet acceptance criteria. The additional inspections are completed within the interval in which the original test was conducted. If subsequent tests do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of tests. The additional tests include at least one test at the other unit with the same material, environment, and aging effect combination. d. Main drains for the standpipes associated with hose stations within the scope of subsequent license renewal will also be added to main drain testing procedures.	B2.1.16	Program will be implemented and inspections or tests begin 5 years before the subsequent period of extended operation. Inspections or tests that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
16	*Fire Water System* program	4. Procedures will be revised to perform internal visual inspections of sprinkler and deluge system piping to identify internal corrosion, foreign material, and obstructions to flow. Follow-up volumetric examinations will be performed if internal visual inspections detect ~~age-related degradation in excess of what would be expected accounting for design, previous inspection experience, and inspection interval.~~an unexpected level of degradation due to corrosion product deposition. If organic or foreign material, or internal flow blockage that could result in failure of system function is identified, then an obstruction investigation will be performed within the Corrective Action Program that includes removal of the material, an extent of condition determination, review for increased inspections, extent of follow-up examinations, and a flush in accordance with NFPA 25, 2011 Edition, Annex D.5, Flushing Procedures. The internal visual inspections will consist of the following: (Relocated from Enhancement 10 and Corrected - Change Notice 2) a. Wet pipe sprinkler systems - 50% of the wet pipe sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote sprinkler, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. During the next five-year inspection period, the alternate systems previously not inspected shall be inspected. b. Pre-action sprinkler systems - pre-action sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. c. Deluge systems - deluge systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. 5. Procedures will be revised to perform system flow testing at flows representative of those expected during a fire. A flow resistance factor (C-factor) will be calculated to compare and trend the friction loss characteristics to the results from previous flow tests. ~~6. Procedures for hydrant flushing will be revised to require fully opening the hydrant and fully flowing the hydrant for no less than one minute and until foreign material has cleared. In addition, procedures will be revised to observe draining of the hydrant barrel and also require the barrel be pumped dry should it not drain within 60 minutes. Hydrants outside the protected area that are within the scope of subsequent license renewal will be added to the flush scope.~~ (Completed Change Notice 1) 7. The Fire Water System program will be revised to periodically inspect the insulated exterior surfaces of the fire water tanks on a 10-year frequency during the subsequent period of operation. Insulation is removed to provide a minimum inspection population of 25 one-square foot samples. The samples will be distributed in such a way that inspections occur on the tank dome, near the tank bottom, at points where structural supports, pipe, or instrument nozzles penetrate the insulation and where water could collect. In addition, inspection locations will be based on the likelihood of corrosion under insulation occurring. ~~8. Procedures for mainline strainer flushing will be revised to require flushing until clear water is observed after each operation or flow test. In addition to flushing after operation, the Radwaste Facility mainline strainer will require an inspection every five years for damaged and corroded parts.~~ (Completed Change Notice 1)	B2.1.16	Program will be implemented and inspections or tests begin 5 years before the subsequent period of extended operation. Inspections or tests that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
16	*Fire Water System* program	9. A procedure will be created to provide a Turbine Building oil deluge systems spray nozzle air flow test to ensure that patterns are not impeded by plugged nozzles, to ensure that nozzles are correctly positioned, and to ensure that obstructions do not prevent discharge patterns from wetting surfaces to be protected. 10. ~~Procedures will be revised to perform internal visual inspections of sprinkler and deluge system piping to identify internal corrosion, foreign material, and obstructions to flow. Follow up volumetric examinations will be performed if internal visual inspections detect age-related degradation in excess of what would be expected accounting for design, previous inspection experience, and inspection interval.an unexpected level of degradation due to corrosion product deposition. If organic or foreign material, or internal flow blockage that could result in failure of system function is identified, then an obstruction investigation will be performed within the Corrective Action Program that includes removal of the material, an extent of condition determination, review for increased inspections, extent of follow-up examinations, and a flush in accordance with NFPA 25, 2011 Edition, Annex D.5, Flushing Procedures. The internal visual inspections will consist of the following:~~ (Relocated to Enhancement 4 - Change Notice 2) ~~a. Wet pipe sprinkler systems – 50% of the wet pipe sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote sprinkler, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. During the next five year inspection period, the alternate systems previously not inspected shall be inspected.~~ ~~b. Pre action sprinkler systems – pre action sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.~~ ~~c. Deluge systems – deluge systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.~~ 11. Procedure will be revised to provide inspection guidance related to lighting, distance and offset for non-ASME Code inspections. The procedure will specify adequate lighting be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two to four feet (or less) will be appropriate. For distant surface inspections, viewing aids such as binoculars may be used. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used. 12. The Unit 1 hydrogen seal oil system deluge sprinkler pipe and Unit 1 station main transformer '1A' deluge sprinkler piping will be reconfigured to allow drainage. 13. The program will be revised to require inspections and tests be performed by personnel qualified in accordance with site procedures and programs for the specified task. (Added Change Notice 2)	B2.1.16	Program will be implemented and inspections or tests begin 5 years before the subsequent period of extended operation. Inspections or tests that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
16	*Fire Water System* program	14. Procedures will be revised to require when degraded coatings are detected by internal coating inspections, acceptance criteria and corrective action recommendations consistent with the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers and Tanks (B2.1.28) program are followed in lieu of NFPA 25 section 9.2.7 (1), (2), and (4). When interior pitting or general corrosion (beyond minor surface rust) is detected, tank wall thickness measurements are conducted as stated in NFPA 25 Section 9.2.7(3) in vicinity of the loss of material. Vacuum box testing as stated in NFPA 25 Section 9.2.7(5) is conducted when pitting, cracks, or loss of material is detected in the immediate vicinity of welds.(Added Change Notice 2) 15. Procedures will be revised to address recurring internal corrosion with the use of Low Frequency Electromagnetic Technique (LFET) or a similar technique on 100 feet of piping during each refueling cycle to detect changes in the pipe wall thickness. LFET screening or a similar technique will also be performed on accessible interior fire water storage tank bottoms during periodic inspections. The procedure will specify thinned areas found during the LFET screening be followed up with pipe wall thickness examinations to ensure aging effects are managed and wall thickness is within acceptable limits. In addition to the pipe wall thickness examination, the performance of opportunistic visual inspections of the fire protection system will be required whenever the fire water system is opened for maintenance.	B2.1.16	Program will be implemented and inspections or tests begin 5 years before the subsequent period of extended operation. Inspections or tests that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
18	*Fuel Oil Chemistry* program	The *Fuel Oil Chemistry* program is an existing mitigative and condition monitoring and preventive program that will be enhanced as follows: 1. Procedures will be revised to include the emergency diesel generator (EDG) fuel oil base tanks within the scope of the *Fuel Oil Chemistry* program. 2. Existing procedures will be revised to include a requirement for quarterly sampling of the EDG auxiliary fuel oil tanks and EDG fuel oil base tanks for particulates and water. 3. Procedures will be revised to require the following fuel oil storage tanks within the scope of subsequent license renewal be drained, cleaned, and the internal surfaces visually inspected for degradation within ten years of entering the subsequent period of extended operation, and every ten years during the subsequent period of extended operation: • Underground fuel oil storage tanks • AAC diesel generator fuel oil tank If degradation is found during the internal visual inspection, bottom thickness measurements will be performed. Visual and volumetric examinations will be performed by personnel qualified in accordance with the standards of the American Petroleum Institute. 4. Procedures will be developed to perform periodic bottom thickness measurements of the following tanks within ten years of entering the subsequent period of extended operation, and every ten years during the subsequent period of extended operation: • EDG auxiliary fuel oil tanks • Diesel fire pump fuel oil tank • Emergency service water pump fuel oil tank Volumetric examinations will be performed by personnel qualified in accordance with the standards of the American Petroleum Institute. 5. Procedures will be developed to require an engineering evaluation be performed to document, evaluate, and trend visual and volumetric (as applicable) inspection results for the following fuel oil storage tanks: • Underground fuel oil storage tanks • AAC diesel generator fuel oil tank • EDG auxiliary fuel oil tanks • Diesel fire pump fuel oil tank • Emergency service water pump fuel oil tank	B2.1.18	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
18	*Fuel Oil Chemistry* program	The procedures will require unacceptable inspection results, as determined in the engineering evaluation, be documented in the Corrective Action Program. Bottom thickness measurements will be required to be evaluated against the design thickness and corrosion allowance. The frequency ~~between~~ of future inspections will not be allowed to be reduced if bottom thickness measurements indicate the corrosion allowance will be exceeded prior to the next scheduled inspection. (Revised Change Notice 2) If a tank does not have a stated corrosion allowance, the tank will be evaluated for acceptability in the engineering evaluation. The engineering evaluation will evaluate the need to reduce the time period between future inspections based on inspection results. 6. Prior to the subsequent period of extended operation, a one-time inspection will be performed on the accessible internal surfaces on one EDG fuel oil base tank at SPS. Inspection will be limited due to the restricted accessibility through the tank sampling port. A visual inspection will be performed using a boroscope or equivalent instrument which will provide an acceptable level of information regarding tank degradation on the accessible internal surfaces. 7. Procedures will be revised to require a biocide be added when biological activity is detected or if there is evidence of tank internal corrosion.	B2.1.18	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
25	*Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program	The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to require inspection of metallic components for flaking or oxide-coated surfaces. 2. Procedures will be revised to require inspection of elastomeric and flexible polymeric components for the following: a. Surface crazing, scuffing, loss of sealing, blistering, and dimensional change (e.g., "ballooning" and "necking") b. Loss of wall thickness c. Exposure of internal reinforcement (e.g., reinforcing fibers, mesh, or underlying metal) for reinforced elastomers 3. Procedures will be revised to specify that visual inspection of elastomeric and flexible polymeric components is supplemented by tactile inspection to detect hardening or loss of suppleness. The minimum surface area for tactile inspections will be at least 10% of the accessible surface area. 4. Procedures will be revised to provide non-ASME Code inspection guidance related to lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. The procedure will specify adequate lighting be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two feet or less will be appropriate. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used. For internal inspections, accessible surfaces will be inspected. If inspecting piping internal surfaces, a minimum of one linear foot will be inspected, if accessible. Cleaning will be performed, as necessary, to allow for a meaningful examination. If protective coatings are present, the procedure will require the condition of the coating to be documented. 5. Procedures will be revised to specify that follow-up volumetric examinations are performed where irregularities that could be indicative of an unexpected level of degradation are detected for steel components exposed to raw water, raw water (potable), or waste water. (Added Change Notice 2) 6. A new procedure will be developed to specify that in each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed for the various sample populations (each material, environment, and aging effect combination). If opportunistic inspections will not fulfill the minimum number of inspections by the end of each 10-year period, the program owner will initiate work orders as necessary to request additional inspections. A representative sample of 20% of the population (defined as components having the same material, environment, and aging effect combination) or a maximum of nineteen components per population at each unit will be inspected. The new procedure will specify that the inspections focus on the bounding or lead components most susceptible to aging due to time in service and severity of operating conditions.	B2.1.25	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
25	*Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program	7. A new procedure will be developed to evaluate and project the rate of any degradation until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection sampling bases (e.g., selection, size, frequency) will be adjusted as necessary based on the projection. 8. A new procedure will be developed to specify that, where practical, acceptance criteria are quantitative (e.g., minimum wall thickness). For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions. 9. A new procedure will be developed to specify that additional inspections will be performed if any sampling-based inspections do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination are inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the next refueling outage interval.	B2.1.25	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
26	*Lubricating Oil Analysis* program	The *Lubricating Oil Analysis* Program is an existing preventive program that will be enhanced as follows: 1. Procedures will be revised to incorporate existing guidelines for lube oil and electro-hydraulic control fluids into sampling procedures. 2. Procedures will be revised to include a statement that phase-separated water in any amount is not acceptable.	B2.1.26	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
34	*Structures Monitoring* program	The *Structures Monitoring* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to include inspection of the following structures that are within the scope of subsequent license renewal: decontamination building, radwaste facility, health physics yard office building, laundry facility, and machine shop. Inspections for the added structures will be performed under the enhanced program in order to establish quantitative baseline inspection data prior to the subsequent period of extended operation.(Revised Change Notice 2) 2. Procedures will be revised to include preventive actions to ensure bolting integrity for replacement and maintenance activities by specifying proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. 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," will be used. 3. The checklist for structural and support steel will be revised to indicate: "Are any connection members loose, missing or damaged (bolts, rivets, nuts, etc.)?". (Added Change Notice 2) ~~4. Procedures will be revised to require at least five years of experience (or ACI inspector certification) for concrete inspectors to be consistent with ACI 349.3R 002.~~ Procedures will be revised to eliminate options for inspector qualifications that are not consistent with ACI 349.3R-002.(Revised Change Notice 2) ~~5. Procedures will be revised to inspect wooden power poles on a 10 year frequency.~~ Procedures will be revised to specify that wooden pole inspections will be performed every ten years by an outside firm that provides wooden pole inspection services that are consistent with standard industry practice. Visual examinations may be augmented with soundings or other techniques appropriate for the type, condition, and treatment of the wooden poles, including borings to determine the location and extent of decay and excavation to determine the extent of decay at the groundline. (Revised Change Notice 2) 6. Procedures will be revised to specify that evaluation of inspection results includes consideration of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. (Added Change Notice 2) 7. Procedures will be enhanced to specify VT-1 inspections to identify cracking on stainless steel and aluminum components. A minimum of 25 inspections will be performed every ten years during the subsequent period of extended operation from each of the stainless steel and aluminum component populations assigned to the Structures Monitoring program. If the component is measured in linear feet, at least one foot will be inspected to qualify as an inspection. For other components, at least 20% of the surface area will be inspected to qualify as an inspection. The selection of components for inspection will consider the severity of the environment. For example, components potentially exposed to halides and moisture would be inspected, since those environmental factors can facilitate stress corrosion cracking. (Added Change Notice 2)	B2.1.34	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

#	Program	Commitment	AMP	Implementation
34	*Structures Monitoring* program	<u>8. Procedures will be enhanced to specify for the sampling-based inspections to detect cracking in stainless steel and aluminum components, additional inspections will be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. No fewer than five additional inspections for each inspection that did not meet acceptance criteria or 20 percent of each applicable material, environment, and aging effect combination will be inspected, whichever is less. Additional inspections will be completed within the 10-year inspection interval in which the original inspection was conducted. The responsible engineer will initiate condition reports to generate work orders to perform the additional inspections. The responsible engineer will evaluate the inspection results, and if the subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted. The responsible engineer will then 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 of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. 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 Corrective Action Program. (Added Change Notice 2)</u>		
35	*Inspection of Water Control Structures Associated with Nuclear Power Plants* program	The *Inspection of Water Control Structures Associated with Nuclear Power Plants* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to provide guidance for specification of bolting material, lubricants and sealants, and installation torque or tension to prevent degradation and assure structural bolting integrity. 2. Procedures will be revised to specify the preventive actions for storage discussed in Section 2 of Research Council for Structural Connections publication "Specification for Structural Joints Using ASTM A325 or A490 Bolts" for ASTM A325, ASTM F1852, ASTM F2280, and/or ASTM A490 structural bolts. 3. Procedures will be revised for concrete inspection to require at least five years of experience (or ACI inspector certification) to be consistent with ACI 349.3R-2002.	B2.1.35	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
36	*Protective Coating Monitoring and Maintenance* program	The *Protective Coating Monitoring and Maintenance* program is an existing mitigative and condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to require that a pre-inspection review of the previous "two" condition assessment reports be performed prior to each refueling outage.	B2.1.36	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
39	*Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program	The *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to require inspection of in-scope manholes after event driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding. 2. Procedures will be revised to add a step stating that automatic or passive drainage features of manholes are operating properly. 3. A procedure will be created for testing medium-voltage cable that includes a requirement for testing medium-voltage cables that are exposed to significant moisture to determine the condition of the electrical insulation. 4. Procedures will be revised to add a step to evaluate adjusting the inspection frequency of manholes based on plant-specific operating experience over time with water collection. 5. A new recurring event and maintenance schedule will be created for testing the "A" RSST cables at least once every six years. 6. A new recurring event and maintenance schedule will be created for testing the "B" RSST cables at least once every six years. 7. A new recurring event and maintenance schedule will be created for testing the "C" RSST cables at least once every six years. 8. A new procedure will be created for testing medium-voltage cable that includes a requirement that the specific type of test performed will be a proven test, utilizing one or more tests such as dielectric loss (dissipation factor (Tan-Delta)/power factor), AC voltage withstand, partial discharge, step voltage, time domain reflectometry, insulation resistance and polarization index, or line resonance analysis, for detecting deterioration of the insulation system due to submergence (e.g., selected test is applicable to the specific cable construction: shielded and non-shielded, and the insulation material under test). 9. A plant-specific inaccessible medium-voltage cable test matrix that documents inspection methods, test methods, and acceptance criteria for the in-scope inaccessible medium-voltage power cables will be developed based on OE. (Added Change Notice 2) 10. A new procedure will be created for testing medium-voltage cable that includes a requirement to review visual inspection and physical test results that are trendable and repeatable to provide additional information on the rate of cable or connection insulation degradation. 11. A new procedure will be created for testing medium-voltage cable that includes acceptance criteria for tests and inspections.	B2.1.39	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
27	*Buried and Underground Piping and Tanks* program	The *Buried and Underground Piping and Tanks* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to establish an upper limit of -1200mV for pipe-to-soil potential measurements of coated pipes so as to preclude potential damage to coatings. ~~2. Procedures will be revised to include visual inspection requirements and acceptance criteria for:~~ ~~a. Absence of cracking in fiberglass reinforced plastic components and evaluation of blisters, gouges, or wear~~ ~~b. Minor cracking and loss of material in concrete or cementitious material provided there is no evidence of leakage exposed or rust staining from rebar or reinforcing "hoop" bands~~ (Completed Change Notice 2) 3. Procedures will be revised to specify that cathodic protection surveys use the -850mV polarized potential, instant off criterion specified in NACE SP0169-2007 for steel piping acceptance criteria unless a suitable alternative polarization criteria can be demonstrated. Alternatives include the -100mV polarization criteria, -750mV criterion (soil resistivity is less than 100,000 ohm-cm), -650mV criterion (soil resistivity is greater than 100,000 ohm-cm), or verification of less than 1 mpy loss of material rate. Alternatives will be demonstrated to be effective through verification of soil resistivity every five years, use of buried coupons, electrical resistance probes, or placement of reference cells in the immediate vicinity of the piping being measured. As an alternative to verifying the effectiveness of the cathodic protection system every five years, soil resistivity testing is conducted annually during a period of time when the soil resistivity would be expected to be at its lowest value (e.g., maximum rainfall periods). Upon completion of ten annual consecutive soil samples, soil resistivity testing can be extended to every five years if the results of the soil sample tests consistently have verified that the resistivity did not fall outside of the range being credited (e.g., for the -750 mV relative to a CSE, instant off criterion, measured soil resistivity values were greater than 10,000 ohm-cm). (Revised Change Notice 2) When using the electrical resistance corrosion rate probes: a. The individual determining the installation of the probes and method of use will be qualified to NACE CP4, "Cathodic Protection Specialist" or similar b. The impact of significant site features and local soil conditions will be factored into placement of the probes and use of the data	B2.1.27	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
28	*Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program	The *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to require additional inspections (100 percent of accessible coatings/linings) of the following tanks, piping, and miscellaneous components within the scope of subsequent license renewal and inspection frequencies will be modified, as necessary, to ensure consistency with NUREG-2191: (Revised Change Notice 2) • Circulating water system waterbox air separating tanks • Condensate polishing outlet piping (short segment; entire length is inspected) • Vacuum priming tanks • Vacuum priming seal water separator tanks • Auxiliary steam drain receiver tank • Water treatment piping (short segment; entire length is inspected) • Flash evaporator demineralizer isolation valve • Brominator mixing tank • Pressurizer relief tanks 2. Programs will be revised to consistently reference coating aging mechanisms and add definitions for rusting, wear/erosion, and physical damage. 3. Procedures will be revised to require alignment of the internal coating/lining inspection criteria with the inspection criteria and aging mechanisms specified in the Coatings Condition Assessment Program. 4. Procedures will be revised to require inspections of cementitious coatings/linings and include aging mechanisms associated with cementitious coatings/linings described as cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation. 5. Procedures will be revised to require cementitious coatings/linings inspectors to 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. 6. Procedures will be revised to require opportunistic inspections of piping internally lined with concrete and include aging associated with cementitious coatings/linings described as cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation. (Added Change Notice 2) 7. Procedures will be revised to require a pre-inspection review of the previous "two" condition assessment reports, when available, be performed, to review the results of inspections and any subsequent repair activities. 8. Procedures will be revised to require inspection results are evaluated against acceptance criteria to confirm that the components' intended functions will be maintained throughout the subsequent period of extended operation based on the projected rate and extent of degradation. Where practical, (e.g., wall thickness measurements, blister size and (frequency), degradation is projected until the next scheduled inspection. (Added Change Notice 2)	B2.1.28	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
28	*Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program	9. Procedures will be revised to: a. Specify there are no indications of peeling or delamination. (Revised Change Notice 2) b. Require inspection of cementitious coatings/linings. Minor cracking and spalling is acceptable provided there is no evidence that the coating/lining is debonding from the base material. c. Require, as applicable wall thickness measurements, projected to the next inspection, meet design minimum wall requirements. (Revised Change Notice 2) 10. Procedures will be revised to permit the "removal" of coatings/linings that do not meet acceptance criteria, with the required evaluation and documentation. 11. Procedures will be revised to include as an alternative to repair, rework, or removal, internal coatings/linings exhibiting indications of peeling and delamination. The component may be returned to service if: a. Physical testing is conducted to ensure that the remaining coating is tightly bonded to the base metal b. ~~The~~ the potential for further degradation of the coating is minimized, (i.e., any loose coating is removed, the edge of the remaining coating is feathered), ~~adhesion testing (e.g., pull-off testing, knife adhesion testing) is conducted at a minimum of three sample points adjacent to the defective area~~ (Revised Change Notice 2 c. adhesion testing using ASTM International Standards endorsed in RG 1.54 (e.g., pull-off testing, knife adhesion testing) is conducted at a minimum of 3 sample points adjacent to the defective area. (Revised Change Notice 2 d. ~~An~~ an evaluation is conducted of the potential impact on the system, including degraded performance of downstream components due to flow blockage and loss of material or cracking of the coated component, and (Revised Change Notice 2 e. ~~Follow-up~~ follow-up visual inspections of the degraded coating are conducted within two years from detection of the degraded condition, with a re-inspection within an additional two years, or until the degraded coating is repaired or replaced. (Revised Change Notice 2 12. Procedures will be revised to require when a blister does not meet acceptance criteria, and it is not repaired, physical testing is conducted to ensure that the blister is completely surrounded by sound coating/lining bonded to the surface. Physical testing consists of adhesion testing using ASTM International standards endorsed in RG 1.54. Where adhesion testing is not possible due to physical constraints, another means of determining that the remaining coating/lining is tightly bonded to the base metal is conducted such as lightly tapping the coating/lining. Acceptance of a blister to remain inservice should be based both on the potential effects of flow blockage and degradation of the base material beneath the blister. ~~additional inspections if one of the license renewal inspections does not meet acceptance criteria due to current or projected degradation.~~ (Revised Change Notice 2)	B2.1.28	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
28	*Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program	13. Procedures will be revised to require additional inspections be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending) unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. The number of increased inspections will be determined in accordance with the Corrective Action Program. However, there are no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. When inspections are based on the percentage of piping length, an additional 5% of the total length will be inspected. The timing of the additional inspections will be based on the severity of the degradation identified and will be commensurate with the potential for loss of intended function. However, in all cases, the additional inspections will be completed within the interval in which the original inspection was conducted, or if identified in the latter half of the current inspection interval, within the next refueling outage interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections. Additional samples will be inspected for any recurring degradation to provide reasonable assurance that corrective actions appropriately address the associated causes. The additional inspections will include inspections with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. (Added Change Notice 2) 14. Physical testing is performed where physically possible (i.e., sufficient room to conduct testing) or examination is conducted to ensure that the extent of repaired or replaced coatings/linings encompasses sound coating/lining material. (Added Change Notice 2)	B2.1.28	Program will be implemented and inspections begin 10 years before the subsequent period of extended operation. Inspections that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
29	*ASME Section XI, Subsection IWE* program	The *ASME Section XI, Subsection IWE* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be revised to specify that whenever replacement of bolting is required, bolting material, installation torque or tension, and use of lubricants and sealants are in accordance with the guidelines of EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants," EPRI TR-104213, "Bolted Joint Maintenance & Application Guide," and the additional recommendations of NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation of Failure in Nuclear Power Plants." 2. Procedures will be revised to specify that for structural bolting consisting of ASTM A325, ASTM F1852, and/or ASTM A490 bolts, the preventive actions for storage, lubricants, and stress corrosion cracking potential discussed in Section 2 of RCSC (Research Council for Structural Connections) publication "Specification for Structural Joints Using ASTM A325 or A490 Bolts," will be used. 3. ~~Procedures will be revised to specify surface examination and acceptance criteria, in addition to visual examination, to detect cracking in stainless steel and dissimilar metal welds of penetration sleeves and components that are subject to cyclic loading but have no current licensing basis (CLB) fatigue analysis.~~Procedures will be revised to augment visual examinations with surface examinations to manage cracking in the containment pressure retaining portions of the fuel transfer tube, fuel transfer tube enclosure, fuel transfer tube blind flange, dissimilar metal weld penetrations, and high-temperature steel piping penetrations. Surface examinations will be performed once during each ten year interval. (Revised Change Notice 2) 4. Procedures will be revised to specify a one-time volumetric examination of metal liner surfaces that are inaccessible from one side if triggered by plant-specific operating experience. ~~Sampling locations will be those susceptible to loss of thickness due to corrosion of the Containment liner that is inaccessible from one side.~~The trigger for this supplemental examination is plant-specific occurrence or recurrence of measurable metal liner corrosion (base metal material loss exceeding 10% of nominal plate thickness) initiated on the inaccessible side or areas, identified since the date of issuance of the initial renewed license. This supplemental volumetric examination consists of a sample of one-foot square locations that include both randomly-selected and focused areas most likely to experience degradation based on operating experience and/or other relevant considerations such as environment. Any identified degradation is addressed in accordance with the applicable provisions of the ASME Section XI, Subsection IWE program. The sample size, locations, and any needed scope expansion (based on findings) for this one-time set of volumetric examinations should be determined on a plant-specific basis to demonstrate statistically, with 95% confidence, that 95% of the accessible portion of the containment liner is not experiencing corrosion degradation with greater than 10% loss of nominal thickness. (Revised Change Notice 2)	B2.1.29	Program and SLR enhancements, will be implemented 6 months prior to the subsequent period of extended operation. ~~and if triggered by plant-specific operating experience, a one-time supplemental volumetric examination by sampling randomly selected as well as focused locations susceptible to loss of thickness due to corrosion of containment shell or liner that is inaccessible from one side is completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.~~(Revised Change Notice 2)

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
31	*ASME Section XI, Subsection IWF* program	The *ASME Section XI, Subsection IWF* program is an existing condition monitoring program that will be enhanced as follows: 1. Procedures will be enhanced to evaluate the acceptability of inaccessible areas (e.g., portions of supports encased in concrete, buried underground, or encapsulated by guard pipe) when conditions in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. 2. Procedures will be revised to specify that whenever replacement of bolting is required, bolting material, installation torque or tension, and use of lubricants and sealants will be in accordance with the guidelines of EPRI NP-5769, EPRI TR-104213, and the additional recommendations of NUREG-1339. 3. Procedures will be revised to specify that for structural bolting consisting of ASTM A325, ASTM F1852, and/or ASTM A490, the preventive actions for storage, lubricants, and stress corrosion cracking potential discussed in Section 2 of RCSC (Research Council for Structural Connections) publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts," will be used. 4. Procedures will be revised to specify that for NSSS component supports, Class 1 high strength bolting greater than one inch nominal diameter, including ASTM A325 and/or ASTM A490 bolts (including respective equivalent twist-off type ASTM F1852 and/or ASTM F2280 bolts), will be monitored for SCC. 5. Procedures will be revised to specify a one-time inspection within five years prior to entering the subsequent period of extended operation of an additional 5% of the sample populations for Class 1, 2, and 3 piping supports. The additional supports will be selected from the remaining population of IWF piping supports and will include components that are most susceptible to age-related degradation. 6. Procedures will be revised to specify that, for NSSS component supports, high-strength bolting greater than one inch nominal diameter, volumetric examination comparable to that of ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 will be performed to detect cracking in addition to the VT-3 examination. In each 10-year period during the subsequent period of extended operation, a representative sample of bolts will be inspected. The sample will be 20% of the population (for a material / environment combination) up to a maximum of 25 bolts. 7. Procedures will be revised to specify that, if a component support does not exceed the acceptance standards of IWF-3400, but is electively repaired to as-new condition, then the sample is increased or modified to include another support that is representative of the remaining population of supports that were not repaired. (Added Change Notice 2)	B2.1.31	Program will be implemented and a one-time inspection of an additional 5% of the sample size specified in Table IWF-2500-1 for Class 1, 2, and 3 piping supports is conducted within 5 years prior to the subsequent period of extended operation, and are to be completed prior to the subsequent period of extended operation, are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.
32	*10 CFR 50, Appendix J* program	The *10 CFR 50, Appendix J* program is an existing performance monitoring program that is credited.	B2.1.32	Ongoing

B2 AGING MANAGEMENT PROGRAMS

Table B2-1 lists the aging management programs described in this appendix and identifies the programs consistency with NUREG-2191. As discussed in Section B1.4, both plant specific and industry operating experience has been reviewed and considered as it relates to both new and existing aging management programs.

Table B2-1
SPS Program Consistency with NUREG-2191 Program

NUREG-2191 Program	Appendix B Reference	Existing or New	Program has NUREG-2191 Enhancements	Program has Exceptions to NUREG-2191
ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	B2.1.1	Existing	X	
Water Chemistry (Primary and Secondary)	B2.1.2	Existing		X
Reactor Head Closure Stud Bolting (addressed by ISI program)	B2.1.3	Existing	X	X
Boric Acid Corrosion	B2.1.4	Existing		
Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-induced Corrosion in Reactor Coolant Pressure Boundary Components	B2.1.5	Existing		
Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	B2.1.6	Existing		
PWR Vessel Internals	B2.1.7	Existing	X	
Flow-Accelerated Corrosion	B2.1.8	Existing	X	
Bolting Integrity	B2.1.9	Existing	X	
Steam Generators	B2.1.10	Existing		
Open-Cycle Cooling Water System	B2.1.11	Existing	X	X
Closed Treated Water Systems	B2.1.12	Existing	X	X

Table B2-1
SPS Program Consistency with NUREG-2191 Program

NUREG-2191 Program	Appendix B Reference	Existing or New	Program has NUREG-2191 Enhancements	Program has Exceptions to NUREG-2191
Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	B2.1.13	Existing	X	
Compressed Air Monitoring	B2.1.14	Existing	X	
Fire Protection	B2.1.15	Existing		
Fire Water System	B2.1.16	Existing	X	X
Outdoor and Large Atmospheric Metallic Storage Tanks	B2.1.17	Existing	X	X
Fuel Oil Chemistry	B2.1.18	Existing	X	X
Reactor Vessel Material Surveillance	B2.1.19	Existing	X	
One-Time Inspection	B2.1.20	New		
Selective Leaching	B2.1.21	New		
ASME Code Class 1 Small-Bore Piping	B2.1.22	New		X
External Surfaces Monitoring of Mechanical Components	B2.1.23	Existing	X	
Flux Thimble Tube Inspection	B2.1.24	Existing	X	
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	B2.1.25	Existing	X	
Lubricating Oil Analysis	B2.1.26	Existing	X	
Buried and Underground Piping and Tanks	B2.1.27	Existing	X	
Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	B2.1.28	Existing	X	X
ASME Section XI, Subsection IWE	B2.1.29	Existing	X	X

Table B2-1
SPS Program Consistency with NUREG-2191 Program

NUREG-2191 Program	Appendix B Reference	Existing or New	Program has NUREG-2191 Enhancements	Program has Exceptions to NUREG-2191
ASME Section XI, Subsection IWL	B2.1.30	Existing	X	
ASME Section XI, Subsection IWF	B2.1.31	Existing	X	
10 CFR Part 50, Appendix J	B2.1.32	Existing		
Masonry Walls	B2.1.33	Existing	X	
Structures Monitoring	B2.1.34	Existing	X	
Inspection of Water-Control Structures Associated with Nuclear Power Plants	B2.1.35	Existing	X	
Protective Coating Monitoring and Maintenance	B2.1.36	Existing	X	
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.37	Existing	X	
Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	B2.1.38	Existing	X	
Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.39	Existing	X	
Electrical Insulation for Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.40	New		

Table B2-1
SPS Program Consistency with NUREG-2191 Program

NUREG-2191 Program	Appendix B Reference	Existing or New	Program has NUREG-2191 Enhancements	Program has Exceptions to NUREG-2191
Electrical Insulation for Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.41	New		
Metal-Enclosed Bus	B2.1.42	Existing	X	X
Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	B2.1.43	New		
High-Voltage Insulators	B2.1.44	New		X
Fatigue Monitoring	B3.1	Existing	X	
Neutron Fluence Monitoring	B3.2	Existing		
Environmental Qualification of Electric Equipment	B3.3	Existing	X	

B2.1.8 Flow-Accelerated Corrosion

Program Description

The *Flow-Accelerated Corrosion* program is an existing condition monitoring program that manages wall thinning caused by flow-accelerated corrosion, as well as wall thinning due to erosion mechanisms. Erosion monitoring is performed for the internal surfaces of metallic piping and components to manage the aging effect of wall thinning due to cavitation, flashing, liquid droplet impingement, and solid particle erosion.

The *Flow-Accelerated Corrosion* program is consistent with the Virginia Power response to NRC Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning," and relies on implementation of the EPRI guidelines in Nuclear Safety Analysis Center (NSAC) 202L, Revision 4, "Recommendations for an Effective Flow Accelerated Corrosion Program." The erosion activity implements the recommendations of EPRI 3002005530, "Recommendations for an Effective Program Against Erosive Attack".

The *Flow-Accelerated Corrosion* program includes: (a) identifying flow accelerated corrosion (FAC)-susceptible piping systems and components; (b) developing FAC predictive models to reflect component geometries, materials, and operating parameters; (c) performing analyses of FAC models and, with consideration of operating experience, selecting a sample of components for inspections; (d) inspecting components; (e) evaluating inspection data to determine the need for inspection sample expansion, repairs, or replacements, and to schedule future inspections; and (f) incorporating inspection data to refine FAC models.

The *Flow-Accelerated Corrosion* program tracks and predicts occurrences of wall thinning due to FAC using CHECWORKS-SFA™ software. Changes made in the CHECWORKS-SFA™ model are prepared and implemented by a qualified FAC engineer. Each change is then independently reviewed and validated by a qualified FAC engineer. Evaluations documenting the calculation of wear, wear rate, remaining life, next scheduled inspection, and sample expansion are independently reviewed by a qualified FAC engineer. The CHECWORKS-SFA™ model is evaluated and updated, as required, to reflect any significant changes in plant operating parameters such as power uprates. The CHECWORKS-SFA™ model is also refined by importing actual ultrasonic testing (UT) results from thickness measurements as input for further wear rate analysis, thereby improving the predictive capability of the model for FAC-susceptible components included in the model. Wall thinning information available from the CHECWORKS-SFA™ software is one of the tools used to determine the scope and required schedule for inspections of FAC-susceptible components.

In addition to planned inspections performed for the *Flow-Accelerated Corrosion* program, opportunistic visual inspections of internal surfaces are conducted during routine maintenance activities to identify degradation. The *Flow-Accelerated Corrosion* program goal is to ensure that piping remains above the minimum allowable wall thickness; inspections are scheduled to support a planned approach such that the components wall thickness will be managed until replacement can be scheduled.

While no preventive actions are required by this program, activities such as monitoring of water chemistry to control pH and dissolved oxygen content can be effective in reducing FAC. Similarly, selecting FAC-resistant materials, or changing piping geometry for susceptible locations can be effective in reducing FAC. The aging management strategy related to FAC emphasizes a preference for design improvement over simple management of wall thinning.

NUREG-2191 Consistency

The *Flow-Accelerated Corrosion* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M17, Flow-Accelerated Corrosion.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Scope of Program (Element 1) and Detection of Aging Effects (Element 4)

1. ~~Procedures will be revised to include a re-evaluation of~~An engineering evaluation will be performed for systems ~~currently~~that have been excluded from the FAC program due to no flow or infrequently used lines with a total operating and testing time that is less than 2% of the plant operating time. ~~to ensure that an adequate basis exists to justify continuing this exclusion.~~ The purpose of the engineering evaluation is to confirm the scope of components that will qualify for the exclusion being extended into the subsequent period of extended operation. The engineering evaluation and modeling changes for the FAC program will be completed prior to entering the subsequent period of extended operation.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Flow-Accelerated Corrosion* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

FAC Operating Experience

1. In April 2009, FAC inspections were performed during the refueling outage using the ultrasonic testing technique. Those inspections found that two 1.5 inch nominal OD sections of piping in the main steam system had minimum wall thickness below 65% of nominal, and required replacement. That replacement effort was completed using FAC-resistant piping prior to resuming power operation. A review of the inspection history for the associated lines and for parallel trains was conducted, and a scope expansion of six extra main steam lines was identified. The completion of the follow-on scope expansion and evaluation demonstrated an ongoing focus within the *Flow-Accelerated Corrosion* program for susceptible components.
2. Industry Operating Experience: In August 2009, industry OE described a steam piping failure that caused a plant shutdown. A FAC review revealed a similar small-bore piping arrangement at Unit 2. No similar finding was identified for Unit 1. Accordingly, those pipe sections were replaced during the subsequent Unit 2 refueling outage.
3. In November 2009, as part of the *Flow-Accelerated Corrosion* program, an 18" diameter section of feedwater system piping was UT inspected and found to have inadequate wall thickness, thus requiring replacement during the current refueling outage. A work order was completed to replace the piping section using CrMo material prior to resuming power operation.
4. In November 2010, after a main steam trip valve was removed to allow replacement due to erosion at the lower gasket seat, Engineering performed a visual FAC inspection of the upstream and downstream components. Wall thinning was found on the downstream elbow. The three inch carbon steel elbow was replaced using CrMo material.
5. In April 2011, several components on a ten inch condensate polishing line were UT inspected during the refueling outage as part of the *Flow-Accelerated Corrosion* program. The measured wall thickness for a nozzle was projected to be below the minimum allowable wall thickness prior to the next refueling outage, thus requiring replacement or repair during the current outage. Weld buildup repairs were completed for the nozzle and associated elbow prior to resuming power operation.

6. In December 2015, an effectiveness review of the Flow Accelerated Corrosion Activity (UFSAR Section 18.2.16) was performed. The AMA was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. The results of that review indicated that license renewal references were not included in the Flow Accelerated Corrosion Activity procedures. Resolution was achieved by revising the controlling procedures for the Flow Accelerated Corrosion Activity to provide references to the technical reports or pertinent section of the license renewal application for the license renewal commitments.
7. In November 2016, a fleet self-assessment of the Flow Accelerated Corrosion Activity (UFSAR Section 18.2.16) was completed. The assessment included a review, with industry peers, of standard processes for the Flow Accelerated Corrosion Activity to identify whether they were as efficient and effective as possible. No Areas for Improvement were identified, but it was determined that efficiencies could be gained by implementing more modern technologies. Opportunities for procedure enhancements also were identified. Since 2016, FAC Manager software has been placed in service to automate the process of transferring component evaluation results into CHECWORKS-SFA™. Procedure enhancements continue to be processed.
8. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.
9. In November 2017, as part of oversight review activities, the Flow Accelerated Corrosion Activity (UFSAR Section 18.2.16) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

10. In January 2018, an AMP effectiveness review was performed of the Flow Accelerated Corrosion Activity (UFSAR Section 18.2.16). Information from the summary of that effectiveness review is provided below:

    The Flow Accelerated Corrosion Activity is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. The activity uses ultrasonic testing (UT) to perform wall thickness measurements of piping that is susceptible to FAC in either single or two-phase flow conditions. Visual inspections of the internals of plant piping systems are performed as the equipment is opened for other repairs and/or maintenance to detect flow accelerated corrosion (FAC) degradation. Condition Reports (CRs) for a 10-year period (July 2006-June 2016) have been reviewed to identify examples of degradation resulting from FAC.

    Reviews of FAC inspection results determine whether the component needs to be replaced during the outage in which it was inspected, or whether the remaining wall thickness and measured wear rate justify continued operation until the next inspection opportunity or planned replacement. Inspection results are used to determine whether examination frequencies are appropriate, and whether additional components need to be inspected or replaced to address the extent of degradation in similar components. The application of both visual and UT inspections have been confirmed to be appropriate. CRs are monitored by the Flow Accelerated Corrosion activity owner to identify potential impacts for the Flow Accelerated Corrosion Activity.

    Industry Operating Experience (OE) is discussed during fleet conference calls, and reviews are performed to determine whether a revision of the Flow Accelerated Corrosion Activity is needed. As an example, an OE item from a U.S. nuclear power plant describes an extraction steam drain line failure that caused a unit shutdown. A FAC OE review identified a similar small-bore piping arrangement at Unit 2. Accordingly, those pipe sections were replaced during the subsequent refueling outage. NRC generic communications also are monitored to identify the need for any changes to the Flow Accelerated Corrosion Activity or additions for the scope of inspections.

Erosion Operating Experience

11. In October 2006 the 14" combined recirculation line for the Unit 2 Main Feed Pumps was discovered to have four through-wall, pin-hole leaks, near the top of the pipe in a bend section near the condenser. An evaluation noted that, while FAC issues in this line were addressed under an earlier design change in 2003 and FAC-resistant piping was installed, cavitation-erosion scenarios were not adequately considered or addressed in that design change. In May 2008, as part of a design change to address several problems in feedwater recirculation flow and pump operations, changes were made in the design and arrangement of this affected line, and a diffuser was added to mitigate the cavitation-erosion that was occurring in the recirculation line pipe bend.

12. In December 2007, an NDE inspection was performed on a service water line (Cu-Ni piping) to a safety-related HVAC chiller to monitor degradation (erosion) as a result of previous failure evaluations. The NDE inspection provided additional wall thinning information until a design change could be implemented. The results of NDE indicated that wall thinning due to erosion (likely cavitation) was continuing, however the readings at that time were above the minimum allowable acceptance criterion. Measured wall loss rates indicated that replacement or repairs were needed in the next six to 12 months. A design change was completed in 2008 to install different pumps and globe valves that significantly reduce the flow velocity.

13. In May 2008 during a preventive maintenance activity, UT thicknesses measurements were taken on the Auxiliary Feedwater pumps' recirculation piping downstream of the orifices at Unit 2. This was based upon an event at Millstone in 2006, where a pinhole leak was discovered in the mini-flow recirculation lines downstream of the restricting orifice (RO). Although there was no through-wall leakage for this piping, the results revealed wall thinning. One Unit 2 line was below the code minimum, so the affected piping was replaced in May 2008. Unit 1 NDE inspections were found acceptable.

14. In December 2008, an engineering inspection of a main control room chiller revealed condenser tube erosion, but no leaks. Per Engineering recommendation, Plastocor coating was placed on the tubes of 'A' main control room chiller in June 2009, and on the tubes of 'C' main control room chiller in July 2010.

The above examples of operating experience provide objective evidence that the *Flow-Accelerated Corrosion* program includes activities to (a) identify all susceptible piping systems and components; (b) develop FAC predictive models to reflect component geometries, materials, and operating parameters; (c) perform analyses of models and, with consideration of operating experience, select a sample of components for inspections to identify wall thinning caused by flow-accelerated corrosion to be managed for susceptible components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Flow-Accelerated Corrosion* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Flow-Accelerated Corrosion* program, following enhancement, will effectively manage aging prior to loss of intended function.

Conclusion

The continued implementation of the *Flow-Accelerated Corrosion* program, following enhancement, will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.9 Bolting Integrity

Program Description

The *Bolting Integrity* program is an existing condition monitoring program that manages aging by performing periodic visual inspections for indications of cracking, loss of material due to general, pitting, and crevice corrosion, microbiologically-influenced corrosion, wear, and loss of preload as evidenced by leakage ~~of~~ for safety-related and non safety-related closure bolting ~~for~~on pressure-retaining components within the scope of subsequent license renewal. ~~except for the reactor vessel closure head studs that are addressed in the Reactor Head Closure Stud Bolting program (B2.1.3).~~

The program refers to NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants". NUREG-1339 includes guidance from EPRI report NP-5067, "Good Bolting Practices Volume 1 (Large Bolt Manual)," and from EPRI report NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants".

The listing for EPRI NP-5769 mentions an exception noted in NUREG-1339 for safety-related bolting. That exception is applicable for bolting used in pressure-retaining applications, and indicates that experimentally–verified fastener material properties and fracture mechanics evaluations should be used to ensure that safety-related fasteners are unlikely to be susceptible to stress corrosion cracking. EPRI Report 1015336 is applicable for the Bolting Integrity program, and states that applicable material properties should be confirmed with the fastener manufacturer. EPRI Report 1015336 includes guidance for preventing or mitigating stress corrosion cracking by the proper selection of bolting. Table B-1 of EPRI Report 1015336 lists appropriate bolting, and is a reference for the bolting design standard at SPS.

The *Bolting Integrity* program includes the following additional considerations from NUREG-1339:

- Visual examinations are performed in accordance with the *Boric Acid Corrosion* program (B2.1.4) to detect degradation of pressure boundary bolting caused by boric acid leakage.
- Visual and volumetric examinations are performed in accordance with the *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1) to detect degradation of pressure boundary bolting due to stress corrosion cracking.

Guidance from EPRI Report 1015336, "Nuclear Maintenance Application Center: Bolted Joint Fundamentals," (Table 4-9) is included in the *Bolting Integrity* program as indicated by the following tasks performed by the program:

- Examine all surface areas, especially the thread root area, for evidence of corrosion, cracking, galling, pitting, and mechanical damage.
- Inspect assemblies for proper thread engagement, correct size
- Specify proper lubricant and torque values during maintenance.
- Examine code material requirements, bolt and nut markings, and material identification.

Recommendations from EPRI Report 1015337, "Nuclear Maintenance Application Center: Assembling Gasketed Flanged Bolted Joints," are followed for assembling bolted connections. Preventive measures to preclude or minimize cracking and loss of preload include proper selections of bolting material and lubricant, and proper application of preload. Neolube N-7000 is the lubricant approved for use.

The absence of high-strength pressure-retaining closure bolting precludes the need for volumetric inspections for those components.

The service air/instrument air subsystems, the hydrogen gas subsystem, the nitrogen gas subsystem, and the in-scope portions of the carbon dioxide fire suppression subsystem will be visually inspected on an opportunistic basis as components in the subsystems undergo maintenance, and during planned and unplanned plant walkdown activities.

Potentially submerged pressure-retaining bolting is associated with submersible pumps (primarily sump pumps) for the balance of plant, the emergency service water pumps located at the Low-Level intake Structure, and the recirculation sump screens located in Containment.

- Submerged bolting for the sump pumps will be inspected opportunistically when the inaccessible bolting is made accessible during maintenance activities. In this case, bolt heads are inspected when made accessible, and bolt threads are inspected when joints are disassembled. A procedure enhancement will be developed to include a requirement to inspect the bolt heads and threads. In each 10-year period during the subsequent period of extended operation, a representative sample of bolts heads and threads is inspected. If the required sample opportunities do not occur, bolting integrity will be demonstrated by other means such as trending pump vibrations or performing plant walkdowns to determine whether the sump pumps are maintaining sump levels.
- Submerged bolting inspection for an emergency service water pump will be performed at least once per ten years when the intake structure screenwell is dewatered.
- Closure bolting inspections for the recirculation sump screens ~~and the service air/ instrument air sub-systems~~ will be performed on a sampling basis consistent with the guidance provided for the sump pumps. ~~[Note: only the air sub-systems require aging~~

~~management since the hydrogen gas sub system is not in the scope of components requiring aging management for SLR, and the nitrogen gas sub system does not contain pressure retaining bolting requiring inspection].~~

For the sampling inspections listed above, inspections shall be completed for at least 20% of the population, up to a maximum of 25 bolt heads and threads, for each material/environment combination. The sample size can be reduced to 19 per unit if there are no pertinent differences between the units. The reduced total number of inspections is acceptable based on the following:

- Water chemistry requirements for the two units are identical, and the operating conditions are similar. Any deviations from established water chemistry guidelines are corrected promptly.
- The raw water used for the two units comes from the same source so the probability of differences in susceptibility to aging mechanisms such as microbiologically-influenced corrosion is low.

Operating experience for the two units indicates no significant difference in aging effects for the integrity of pressure-retaining bolting.

For sampling-based inspections, if the cause of the aging effect for each applicable material and environment is not corrected by repair or replacement for all components constructed of the same material and exposed to the same environment, additional inspections are conducted if one of the inspections does not meet acceptance criteria. The number of increased inspections is determined in accordance with the Corrective Action Program; however, no fewer than five additional (or 20%, whichever is less) inspections of different components having the same material/environment/aging effect combination are required for each inspection that did not meet the acceptance criterion. For a two-unit site, the additional inspections include inspections at the same unit, and at the opposite unit, for components having the same material, environment, and aging effect combination. The additional inspections are to be completed within the same interval (e.g., refueling outage or 10-year inspection interval). If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, sampling frequencies are adjusted as determined by the Corrective Action Program.

Inspections and tests are performed by personnel qualified in accordance with procedures and programs to perform the specified task. Inspections within the scope of the ASME Code will follow procedures consistent with the ASME Code. Non-ASME Code inspections follow procedures that include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

The *ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD* program (B2.1.1), includes inspections of closure bolting within the scope of ASME Code, Section XI and supplements this *Bolting Integrity* program. The reactor vessel closure studs are addressed in the

Reactor Head Closure Stud Bolting program (B2.1.3). The following aging management programs for SPS manage aging effects associated with safety-related and non safety-related structural bolting:

- *ASME Section XI, Subsection IWE* program (B2.1.29)
- *ASME Section XI, Subsection IWF* program (B2.1.31)
- *Structures Monitoring* program (B2.1.34)
- *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.35)
- *Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems* program (B2.1.13)

The *External Surfaces Monitoring of Mechanical Components* program (B2.1.23) describes the inspections for non-ASME pressure-retaining closure bolting.

NUREG-2191 Consistency

The *Bolting Integrity* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M18, Bolting Integrity.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Detection of Aging Effects (Element 4)

1. Procedures will be revised to provide inspection guidance related to lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. The procedure will specify adequate lighting be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two feet to four feet (or less) will be appropriate. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used.

Detection of Aging Effects (Element 4)

2. Procedures will be revised for inspections of pressure-retaining closure bolting in locations that preclude detection of joint leakage, such as in submerged environments or where the piping system contains air for which leakage is difficult to detect. The inspections will be performed to detect loss of material. A requirement will be included to inspect bolt heads when made

accessible, and bolt threads if joints are disassembled. At a minimum, in each 10-year interval during the subsequent period of extended operation, inspections shall be completed for a representative sample of at least 20% of the population, up to a maximum of nineteen, for each material/environment combination.

Corrective Action (Element 7)

3. A new procedure will be developed to provide guidance 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, thus requiring that additional inspections 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 of different components having the same material/environment/aging effect combination are required for each inspection that did not meet the acceptance criterion. For a two-unit site, the additional inspections include inspections at the same unit, and at the opposite unit, for components having the same material, environment, and aging effect combination. The additional inspections are to be completed within the same interval (e.g., refueling outage or 10-year inspection interval). If any projected inspection results will not meet acceptance criteria prior to the next scheduled inspection, sampling frequencies are adjusted as determined by the Corrective Action Program.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Bolting Integrity* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In August 2008, the flange bolting on both sides of a Unit 2 service water valve was found to be corroded to the point that the threads were not distinguishable. The joint appeared to be leak-free, but the bolts were in need of replacement. The bolting replacement was completed and the valve was returned to service.
2. In April 2009, during an ASME Code, Section XI pressure test, leakage was noted at a bolted connection on a Unit 1 residual heat removal heat exchanger. ASME Code, Section XI, IWA-5250(a)(2) specifies that if leakage occurs at a bolted connection, one of the bolts shall be removed for a VT-3 examination. The removed bolt had evidence of degradation, thus requiring that all remaining bolting be removed for a VT-3 examination. There are 48 closure bolts. Forty bolts were removed for inspection. Eight bolts could not be removed. Thirty-six of forty bolts removed were rejectable. The forty removed bolts were replaced. An engineering evaluation was written to justify operation for one additional cycle with the eight old bolts in

place. A work order was written to replace the eight bolts that could not be removed during the 2010 outage. However, no additional corrective action was required since the inspection during the 2010 outage found no wastage of the eight bolts and no boric acid leakage on the heat exchanger.

3. In December 2013, EPRI provided notification of Code Noncompliance associated with a Performance Demonstration Initiative (PDI) supporting implementation of ASME Code, Section XI, Appendix VIII, Supplement 8, bolting exams. Applicability involved Class 1 components containing category B-G-1 bolting. Determination of potential impacts required a review of calibration standards used for examination to verify notch size and location, and that the material, size, and geometry are similar to the bolting to be examined. The stud and bolt calibration standards were determined to be acceptable and in full compliance.
4. In November 2015, Engineering performed VT-1 examinations of the Unit 2 'A' steam generator primary manway bolting. Each manway has 16 studs and nuts. One stud had corrosion and possible wear on a non-threaded segment. An engineering evaluation determined that the stud was acceptable for re-use.

The above examples of operating experience provide objective evidence that the *Bolting Integrity* program includes activities to perform visual inspections for indications of cracking, loss of material and loss of preload for pressure-retaining closure bolting within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Bolting Integrity* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Bolting Integrity* program, following enhancement, will effectively manage aging prior to loss of intended function.

Conclusion

The continued implementation of the *Bolting Integrity* program, following enhancement, will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.11 Open-Cycle Cooling Water System

Program Description

The *Open-Cycle Cooling Water System* program is an existing preventive, mitigative, condition monitoring, and performance monitoring program that manages loss of material, reduction of heat transfer, flow blockage, and cracking of the piping, piping components, and heat exchangers identified by the Virginia Electric and Power Company responses to NRC GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment." The program is comprised of the aging management aspects of the Virginia Electric and Power Company response to GL 89-13 and includes: (a) surveillance and control to reduce the incidence of flow blockage problems as a result of biofouling, (b) tests to verify heat transfer of safety-related heat exchangers, (c) routine inspection and maintenance so that loss of material, corrosion, erosion, cracking, fouling, and biofouling cannot degrade the performance of systems serviced by the open-cycle cooling water system. Additionally, recurring internal corrosion (RIC) is addressed in the Corrective Action Program through design modifications that have replaced materials more susceptible to degradation in raw water with materials that are less susceptible to degradation in raw water. This program includes enhancements to the guidance in GL 89-13 that address operating experience such that aging effects are adequately managed.

The open-cycle cooling water system includes those systems that transfer heat from safety-related systems, structures, and components to the ultimate heat sink as defined in GL 89-13.

The guidelines of GL 89-13 are utilized for the surveillance and control of biofouling for the open-cycle cooling water system. Procedures provide instructions and controls for chemical and biocide injection. Periodic sampling procedures monitor free available oxidant at heat exchangers. In addition, periodic flushing, cleanings and/or inspections are performed for the presence of biofouling.

Periodic heat transfer testing, visual inspection, and cleaning of safety-related heat exchangers with a heat transfer intended function is performed in accordance with the site commitments to GL 89-13 to verify heat transfer capabilities. Titanium tubes and tubesheets are scraped in combination with as found visual inspection of the tubesheet for cracking and eddy current testing for tube denting, pits and cracks with additional annual cleaning to minimize pit/crack initiation points.

~~Additionally, s~~Safety-related piping segments are examined (i.e. ultrasonic testing) periodically to ensure that there is no significant loss of material, which could cause a loss of intended function.

Routine inspections and maintenance ensure that corrosion, erosion, sediment deposition (silting), and biofouling do not degrade the performance of safety-related systems serviced by open-cycle cooling water. The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) manages the aging effects of the internal surface coatings.

Aging effects associated with elastomers and flexible polymeric components in the open-cycle cooling water system are managed by the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program (B2.1.25).

The *Buried and Underground Piping and Tanks* program (B2.1.27) manages the aging effects of external surfaces of buried and underground piping and components. The external surface of the aboveground raw water piping and heat exchangers is managed by the *External Surfaces Monitoring of Mechanical Components* program (B2.1.23). The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) will manage the aging effects of internal surface coatings including those of metallic surfaces coated with Carbon Fiber Reinforced Polymer that is used as a pressure boundary.

NUREG-2191 Consistency

The *Open-Cycle Cooling Water System* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI.M20, Open-Cycle Cooling Water System.

Exception Summary

The following program element(s) are affected:

Detection of Aging Effects (Element 4)

1. Section XI.M20 of NUREG-2191, Open-Cycle Cooling Water, indicates that testing intervals can be adjusted to provide assurance that equipment will perform the intended function between test intervals, but should not exceed five years. The *Open-Cycle Cooling Water System* program takes exception to the NUREG-2191 requirement to perform testing of the recirculation spray heat exchangers (RSHXs) at an interval not to exceed five years.

Justification for Exception:

As described in the plant responses to GL-89-13, heat transfer performance testing of the RSHXs is not performed due to system configuration that would require significant design modifications to support such testing. Alternatively, the RSHXs are visually inspected to confirm the absence of indications of degradation. To further reduce the potential for degradation, the internal environment of the RSHXs and the portion of the connected piping that cannot be isolated from the RSHXs is maintained in dry layup (i.e., maintained in an air environment) and the internals of the portion of the inlet piping that is not in dry layup is maintained in wet layup (i.e., a treated water environment that has been chemically treated to maintain a basic pH) to minimize corrosion. The open-cycle cooling water side of the RSHXs are periodically flow tested and visually inspected.

The plant GL 89-13 responses stated that the RSHXs would be flow tested and visually inspected every fourth refueling outage (i.e., every six years) and that the testing and inspection intervals may be modified based on the results of further testing. Based on the results of further testing, the RSHXs are currently flow tested and visually inspected at an interval of eight refueling outages (i.e., every twelve years).

The change in frequency to once every eight refueling outages for RSHXs flow testing and visual inspection was evaluated by Engineering. The evaluation included a review of prior operating experience (flow testing and visual inspection results). Prior flow test results documented between 1997 and 2010 were reviewed. The test results identified little or no blockage, with the exception of a test performed in 2003. The 2003 results revealed 5% blockage, which was still less than the 10% blockage acceptance criteria. RSHXs service water inlet and outlet piping cleaning and inspection are performed on a frequency consistent with RSHXs flow testing. A review of prior piping inspection results between 1996 and 2014 showed the piping to be in satisfactory condition. Although coating defects and areas of corrosion were identified during the piping inspections, the RSHXs were capable of performing their intended function. Required coating and weld repairs were entered in the Corrective Action Program.

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Preventive Actions (Element 2)

1. Selected fiberglass reinforced plastic (FRP) piping in the service water system will be replaced with a more degradation resistant material such as copper-nickel (Cu-Ni) prior to entering the subsequent period of extended operation. FRP piping associated with the Units 1 and 2 charging pump cooling water subsystems, service water rotating strainers, and the control room chillers may be replaced as part of a time-phased program.

2. Modifications necessary to provide new chemical injection site upstream of the service water rotating strainers will be completed prior to entering the subsequent period of extended operation.

3. The internal lining of 24 inch and larger service water inlet piping with carbon fiber reinforced polymer, with the exception of the recirculation spray heat exchanger piping downstream of the inlet motor-operated valves, will be completed prior to entering the subsequent period of extended operation.

Parameters Monitored and Inspected (Element 3)

4. ~~Procedures will be revised to remove reference to the carbon steel piping that was replaced and will include the replacement material.~~(Completed Change Notice 1)

5. Procedures will be revised to provide additional guidance for identifying and evaluating applicable concrete aging effects such as loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; and cracking due to chemical reaction, or corrosion of reinforcement.

Detection of Aging Effects (Element 4)

6. Procedures will be revised to require personnel who perform inspections and evaluation of concrete components to be qualified consistent with the qualifications identified in the *Structures Monitoring* program (B2.1.34) that are consistent with the requirements of ACI 349.3R.

Monitoring and Trending (Element 5)

7. Procedures will be revised to require trending of charging pump lube oil cooler and emergency service water pump engine heat exchanger inspection results by Engineering.

8. Procedures will be revised to require trending of wall thickness measurements. The frequency and number of wall thickness measurements will be based on trending results.

Acceptance Criteria (Element 6)

9. Procedures will be revised to include verification that predicted wall thicknesses at the next scheduled inspection will be greater than the minimum wall thicknesses.

10. Procedures will be revised to include criteria for the extent and rate of on-going degradation that will prompt additional corrective actions.

11. Procedures will be revised to identify acceptance criteria for visual inspection of concrete piping and components such as the absence of cracking and loss of material, provided that minor cracking and loss of material in concrete may be acceptable where there is no evidence of leakage, exposed rebar or reinforcing "hoop" bands or rust staining from such reinforcing elements.

Corrective Actions (Element 7)

12. Procedures will be revised to ensure that for ongoing degradation mechanisms (e.g., MIC), the frequency and extent of wall thickness inspections at susceptible locations are increased commensurate with the significance of the degradation.

13. Procedures will be revised to ensure that when measured parameters do not meet the acceptance criteria, additional inspections are performed, when the cause of the aging effect is not corrected by repair or replacement for components with the same material and environment combination. The number of inspections will be determined by the Corrective Action Program, but no fewer than five additional inspections will be performed for each inspection that did not meet the acceptance criteria, or 20% of the applicable material, environment, and aging effect combination inspected, whichever is less. The additional inspections will include inspections at both Unit 1 and Unit 2 with the same material, environment, and aging effect combination.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Open-Cycle Cooling Water System* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In September 2001, a through wall leak was identified in an eight inch carbon steel control room chiller service water supply line. A through wall leak in similar piping occurred again in September 2005. In May 2006, volumetric inspections measurements identified a location in an eight inch carbon steel control room chiller service water supply line that was less than the minimum allowable wall thickness. A design change was implemented, which replaced the eight inch carbon steel piping with copper-nickel piping.

2. Between August 2007 and July 2009, biofouling of the control room chillers Y-strainers and rotating strainers occurred on multiple occasions. The initial cause was thought to be insufficient backwash flow to the rotating strainers during periods of elevated service water temperatures with one control room chiller operating. Procedure changes were implemented to start an additional pump and backwash the rotating strainers when differential pressure reaches one psid. Further clogging of the Y-strainers resulted in compensatory actions being established. These measures included increased monitoring of control room chiller and service water operating parameters when service water temperature was greater than 80°F, weekly flushing of control room chiller service water lines, and securing the chiller and cleaning the chiller suction strainers when pump suction pressure approached the minimum required net positive suction head.

In July 2009, repeated clogging of the control chiller suction Y-strainers occurred. Additional compensatory measures included more frequent flushing of the control room chiller service water piping, and running a minimum of two control room chillers to minimize system transients, which was determined to exacerbate biofouling of the strainers. In the fall of 2009, a modification was completed that provided additional chemical (biocide) injection into the service water system downstream of the rotating strainers and upstream of the Y-strainers to control biofouling. Chemical injection has proven effective in reducing biofouling of the Y-strainers and associated piping.

3. In October 2009, following sampling of the service water side of the component cooling heat exchangers, chemistry personnel determined the free available oxidant (FAO) readings were below minimum acceptable values, which could jeopardize control of biofouling in the system. The chemical injection pump settings were adjusted to restore the pump discharge pressure. Samples taken following adjustments revealed that the FAO levels were acceptable.

4. In February 2010, augmented volumetric inspections of the component cooling heat exchanger service water supply and discharge piping identified piping wall thicknesses that were less than minimum allowed. A weld repair was performed and the calculation of record was updated to reflect the results of the wall thickness readings. Pipe stresses were determined to be within code allowable. Subsequent wall thickness measurements taken following repairs were acceptable.

5. In January 2012, during the performance of a license renewal inspection of a component cooling heat exchanger, pitting, defective coatings, barnacles, and river debris were identified in the heat exchanger. Corrective actions included replacement of a manway, removal of debris from the heat exchanger, coating repairs, and performance of a weld repair. Inspections performed in April 2013 and February 2016 also identified needed weld repairs to the heat exchanger end bell. A surface examination and system pressure test were performed satisfactorily following weld repairs.

6. In October 2013, during surface preparation and weld inspections, a through wall leak was observed in the 42 inch service water piping adjacent to the motor-operated valve supplying service water to the component cooling water heat exchangers from the '1B' condenser water box tunnel. The cause of pipe wall thinning was determined to be non-application of the pipe internal coating. Historically, the motor-operated valve exhibited seat leakage since original installation. In an effort to control leakage, a blank and a hose were used to divert the leakage. As a result, the piping at the blank was unable to be properly coated. Over time, the lack of coating resulted in significant wall loss. Corrective actions included replacement of the valve with a design which would minimize valve leakage, weld repairs to the piping, and internal coating of the piping. A post-weld surface examination and system pressure test were performed satisfactorily.

7. In November 2013, three through wall leaks were identified in the 42 inch piping upstream of the motor-operated valve supplying service water to the component cooling water heat exchangers from the '1D' condenser water box tunnel. The leaks were identified following sand blasting of the piping in preparation for application of internal coating. Weld repairs were performed to correct the deficiencies. A surface examination and system pressure test were performed satisfactorily subsequent to the repairs.

8. Between September 2015 and September 2016, five leaks occurred in the service water system due to cracking of fiberglass piping. The leaks were either repaired or new piping segments installed in accordance with the work order process. The fiberglass piping in the service water system may be replaced with corrosion resistant material such as copper-nickel as part of a time-phased program.

9. In December 2015, an effectiveness review of the Service Water System Inspections Activity (UFSAR Section 18.2.17) was performed. The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. No gaps were identified by the effectiveness review.

10. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMA was conducted to confirm the following:
    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.

11. In September 2017, as part of oversight activities, of the Service Water Inspections Activity (UFSAR Section 18.2.17) it was noted that commitments for the low level intake screenwell (LLIS) and emergency service water pump suction end bell cleaning/inspections were not being performed and documented consistent with the original License Renewal commitment. The License Renewal commitments for the LLIS cleaning and pump inspections were originally incorporated into the procedure that dewatered the LLIS. The recent license renewal cleaning/inspections were performed by divers using a recurring work activity without dewatering the LLIS. A corrective action was initiated for engineering and outage planning to resolve the inconsistency. It was determined that the cleaning and inspection commitments were satisfactorily completed without dewatering the LLIS. Update of the maintenance strategy and associated documents to allow performance of the license renewal commitments with or without dewatering the LLIS is in progress.

12. In January 2018, an aging management program effectiveness review was performed for the Service Water System Inspections Activity (UFSAR Section 18.2.17). Information from the summary of that effectiveness review is provided below:

    The Service Water System Inspections Activity is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. Key activities of the AMA that were reviewed include the selection of components to be inspected, the inspection of components, the evaluation of inspection results, repairs/replacements, and AMA document updates. Engineering reports from 2004 to 2016 of inspections results were reviewed to confirm inspection frequencies were conducted at appropriate intervals and corrective actions taken consistent with the observed aging degradation. The review also included pertinent issues found in the Corrective Action Program from 2006 through 2017 for age related degradation of open-cycle cooling water system components within the scope of license renewal.

    The key aspects of the *Open-Cycle Cooling Water System* program involve controlling biofouling, testing critical heat exchangers, inspecting and cleaning the system, and designing with robust materials. The program is implemented using an active Service Water System Inspection and Maintenance Program and has a well-established Generic Letter 89-13 Program. These programs govern the approach to compliance with the Nuclear Regulatory Commission (NRC) Generic Letter 89-13, Service Water Problems Affecting Safety-Related Equipment. The Program is inspected every three years by the NRC using Inspection Procedure 71111.07, Heat Sink Performance. The most recent inspection did not identify any findings. Additionally, station effectiveness is assessed by implementing INPO SOER 07-2, Intake Cooling Water Blockage every three years. The assessment reviews operating experience, condition reports, and equipment performance for the three year period. The most recent assessment, completed in September 2016, concluded that open-cycle cooling water equipment has been performing satisfactorily.

    Over the summers of 2007 through 2009, a series of events involving an influx of biological growth from the James River prompted the creation of the Service Water Excellence Plan. The plan has resulted in numerous improvements designed to greatly reduce the adverse effects of biofouling and aging. For example, a biocide injection system has been installed to reduce biological growth, key pieces of safety-related piping have been converted to corrosion and fouling resistant materials, and new monitoring and flushing procedures have been instituted. More recently, since entering the first period of extended operation, the interior of the large diameter open-cycle cooling water piping has begun to be lined with carbon fiber reinforced polymer (CFRP). Surry Power Station is first in the industry to employ this technology. It is predicted that the CFRP will add 50 years of effective service life to the asset. The biocide injection point on the safety-related service water piping will also be relocated to maximize effectiveness.

Recurring Internal Corrosion (RIC)

Recurring internal corrosion, including through-wall failures due to pitting and internal fouling of components, has occurred on several occasions. Corrective actions have been taken previously, and additional actions are scheduled to minimize the likelihood of piping and component degradation due to flow blockage and loss of material in the open-cycle cooling water system. The physical modifications completed or scheduled, and enhancements to operating practices and system design to improve OCCW system resistance to recurrence of internal corrosion are noted below:

The Open-Cycle Cooling Water (OCCW) System program will manage aspects of RIC in the service water system and the circulating water system that are within the scope of the program. The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) will manage loss of material on the internal surfaces of service water system and circulating water system piping that has been lined or coated. The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program (B2.1.25) will manage loss of material on the internal surfaces of service water system and circulating water system piping not covered by NRC Generic Letter 89-13.

Flow Blockage:

Flow blockage in OCCW system piping and components is managed by periodically monitoring control room chiller Y-strainer differential pressure and periodically flushing affected piping flow paths. During times when service water temperatures are elevated, above 80°F, the operations surveillance frequency of monitoring service water suction pressure and rotating strainer differential pressures are increased to intervals as short once every 4 hours and piping flush frequency increased to once daily. As a preventive measure, biocide injection points have been added downstream of the rotating suction strainers and the biocide injection has significantly reduced hydroid attachment and growth. A plant modification is in progress to add additional injection points to the upstream portion of the service water rotating strainers.

Loss of Material in Uncoated Steel Piping:

Loss of material has resulted in recurrent wall thinning and through wall leakage in service water piping in uncoated steel service water piping associated with main control room chillers. Replacement of uncoated steel piping with corrosion resistant copper-nickel piping reduced the susceptibility of the OCCW systems to recurring internal corrosion. There has been no documented recurring internal corrosion on the control room chillers copper-nickel piping or other copper-nickel service water system piping within the scope of subsequent license renewal.

Loss of Material in Copper-Nickel Alloy Heat Exchanger Tubing:

Recurring internal corrosion (loss of material) was experienced in the copper-nickel alloy heat exchanger tubing at and beyond the tube sheet for the main control room chiller condensers, including a condenser that had been recently replaced. The affected heat exchanger components have been cleaned and coated with a protective epoxy coating with the coating extending six inches into the heat exchange tubes. The Corrective Action Program apparent cause evaluation identified that the heat exchanger management program did not require flow to be maintained for an extended period in new 90-10 copper-nickel alloy heat exchangers to permit a protective oxide film to form on the tubes prior to the placement of the heat exchangers into a stagnant wet lay-up condition. Implementing documents have been modified to incorporate this lesson-learned. After epoxy coating and modification of wet layup practices, there has been no documented recurring internal corrosion in the control room chiller condenser copper-nickel alloy tubing at and beyond the tube sheet.

Loss of Material in Coated Steel Piping and Heat Exchanger Channel Heads:

Corrosion-resistant Carbon Fiber Reinforced Polymer (CFRP) liner will be installed in the 96-inch circulating water inlet piping, and 24-, 30-, 36-, 42-, and 48-inch service water supply from the circulating water system to the recirculation spray and supply to the component cooling water heat exchangers. The CFRP system is designed to take the place of the existing carbon steel pipe and will form a repaired pipe within the existing piping that is capable of meeting the design requirements of the station piping. The appropriate relief has been granted for this repair by the NRC. The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) will manage the aging of CFRP in the OCCW systems. For epoxy coated piping sections and heat exchanger channel heads that do not yet have the CFRP lining installed, the *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) will manage the aging of the existing epoxy-coated steel piping.

The above examples of operating experience provide objective evidence that the *Open-Cycle Cooling Water System* program includes activities to perform surveillance and control, heat exchanger testing, and routine inspection and maintenance to identify loss of material, reduction of heat transfer, flow blockage, and cracking of the piping, piping components, and heat exchangers within the scope of subsequent license renewal, as identified by the Virginia Electric and Power Company responses to NRC GL 89-13, and to initiate corrective actions. Occurrences identified under the *Open-Cycle Cooling Water System* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and

B2.1.16 Fire Water System

Program Description

The *Fire Water System* program is an existing condition monitoring program that manages loss of material, flow blockage, cracking and loss of coating integrity for in-scope water-based fire protection systems. This program manages aging effects by conducting periodic visual inspections, flow testing, and flushes. Testing and inspections are conducted on a refueling outage interval as allowed by NUREG-2191, Section XI.M27, Table XI.M27-1, "Fire Water System Inspection and Testing Recommendations". There are no nozzle strainers, glass bulb sprinklers, fire pump suction strainers, or foam water sprinkler systems within the scope of subsequent license renewal.

The *Fire Water System* program will include testing a representative sample of the sprinklers prior to fifty years in service with additional representative samples tested at 10-year intervals. Sprinkler testing will be performed consistent with the 2011 Edition of NFPA 25, "Standard For The Inspection, Testing and Maintenance of Water-Based Fire Protection Systems," Section 5.3.1. The fifty year in-service date for sprinklers is October 26, 2021.

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, were designed and installed with a configuration and pitch to allow draining. With the exception of two locations, Engineering walkdowns confirmed the as-built configuration that allows draining and does not allow water to collect. Corrective actions have been initiated for the two locations to verify a flow blockage condition does not exist and to restore the two locations to original configuration requirements that allow draining and do not allow water to collect. After corrective actions, portions of the water-based fire protection system that have been wetted, but are normally dry, will not be subjected to augmented testing and inspections beyond those required by NUREG-2191, AMP XI.M27, Table XI.M27-1.

The water-based fire protection system is normally maintained at required operating pressure and is monitored such that loss of system pressure is detected and corrective actions initiated. A low pressure condition is alarmed in the Main Control Room by the auto start of the electric motor driven fire pump, followed by the start of the diesel-driven fire pump if the low pressure condition continues to exist. The status of the fire pumps is indicated in the Main Control Room and at the fire pump control panels in the pump house. Both fire pumps may be manually started from the control room.

Piping wall thickness measurements are conducted when visual inspections detect surface irregularities indicative of unexpected levels of degradation. When the presence of organic or inorganic material sufficient to obstruct piping or sprinklers is detected, the material is removed and the source is detected and corrected.

Inspections and tests are performed by personnel qualified in accordance with procedures and programs to perform the specified task. Non-code inspections and tests follow procedures that include inspection parameters for items such as lighting, distance, offset, presence of protective coatings, and cleaning processes that ensure an adequate examination.

If a flow test (i.e., NFPA 25, 2011 Edition, Section 6.3.1) or a main drain test (i.e., NFPA 25, 2011 Edition, Section 13.2.5) does not meet the acceptance criteria due to current or projected degradation, additional tests are conducted. The number of increased tests is determined in accordance with the site's corrective action process; however, there are no fewer than two additional tests for each test that did not meet the acceptance criteria. The additional inspections are completed within the interval (i.e., five years or annual/refueling) in which the original test was conducted. If subsequent tests do not meet the acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of tests required. The additional tests will include at least one test at the other unit on site with the same material, environment, and aging effect combination.

In addition to piping replacement, actions will be taken to address instances of recurring corrosion due to microbiological induced corrosion. Low Frequency Electromagnetic Technique (LFET) or similar scanning technique will be used for screening 100 feet of accessible piping during each refueling cycle to detect changes in the wall thickness of the pipe. Thinned areas found during the LFET scan are followed up with pipe wall thickness examinations to ensure aging effects are managed and that wall thickness is within acceptable limits. In addition to the pipe wall thickness examination, opportunistic visual inspections of the fire protection system will be performed whenever the fire water system is opened for maintenance.

Aging of the external surfaces of buried and underground fire main piping is managed by the *Buried and Underground Piping and Tanks* program (B2.1.27). Loss of material and cracking of the internal surfaces of cement lined buried and underground fire main piping are managed by the *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28).

Aging of the fire water storage tank bottom surfaces exposed to oil soil are managed by the *Outdoor and Large Atmospheric Metallic Storage Tanks* program (B2.1.17).

When degraded coatings are detected during internal inspections of the fire water storage tanks, a~~A~~cceptance criteria, and corrective action recommendations ~~and training/qualification of individuals involved in fire water storage tank internal coating inspections are implemented by~~ of the *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) are followed.

NUREG-2191 Consistency

The *Fire Water System* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI M27, Fire Water System.

Exception Summary

The following program element(s) are affected:

Detection of Aging Effects (Element 4)

1. The fire water storage tanks are insulated carbon steel tanks located in an outdoor environment. NUREG-2191, AMP XI.M27, Table XI.M27-1 and note 10 recommends the insulated external surfaces of fire water storage tanks be inspected for signs of degradation on a refueling outage interval for signs of degradation. This would require insulation removal each refueling cycle. Therefore, inspections of the external carbon steel surfaces of the fire water storage tanks will be performed on a 10-year frequency during the subsequent period of operation.

Justification for Exception:

The line item in NUREG-2191, Section XI.M27, Table XI.M27-1, for water storage tank external surfaces recommends the inspection guidance of NFPA, 2011 Edition, Section 9.2.5.5, which requires inspection of insulated tank surfaces. NFPA, 2011 Edition, Section 9.2.5.5, does not provide specific inspection guidance for corrosion of metallic surfaces under insulation in an outdoor air environment. NUREG-2191, Section XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, element 4, provides inspection guidance for corrosion under insulation for insulated carbon steel tanks located in an outdoor environment. NUREG-2191, Section XI.M29, Table XI.M29-1, recommends a 10-year frequency for corrosion under insulation during the subsequent period of operation.

2. NUREG-2191, Table XI.M27-1, note 10 recommends main drain tests at each water-based system riser to determine if there is a change in the condition of the water piping and control valves on an annual or refueling outage interval. Surry Power Station will perform the main drain tests on twenty percent of the standpipes and risers every refueling cycle.

Justification for Exception

As indicated by NUREG-2191 Table XI.M27-1, note 10, access for some inspections is feasible only during refueling outages which are scheduled every eighteen months. Main drain tests on twenty percent of the standpipes and risers every eighteen months provide adequate information to determine the condition of the fire water piping is maintained consistent with the design basis.

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Acceptance Criteria (Element 6), and Corrective Actions (Element 7)

~~1. Procedures inspection guidance will be revised to require replacement of any sprinkler that shows any of the following: leakage, corrosion, physical damage, loading, painting unless painted by the sprinkler manufacturer, or incorrect orientation. Sprinklers at the following locations will be added to the test scope: The Radwaste Facility, Auxiliary Boiler, Maintenance Building, Condensate Polishing Building, Laundry Building, and Machine Shop Building.~~

2. Prior to 50 years in service, sprinkler heads will be submitted for field-service testing by a recognized testing laboratory consistent with NFPA 25, 2011 Edition, Section 5.3.1. Additional representative samples will be field-service tested every 10 years thereafter to ensure signs of aging are detected in a timely manner.

   For wet pipe sprinkler systems, a one-time test of sprinklers that have been exposed to water including the sample size, sample selection criteria, and minimum time in service of tested sprinklers will be performed. At each unit, a sample of 3% or a maximum of ten sprinklers with no more than four sprinklers per structure shall be tested. Testing is based on a minimum time in service of fifty years and severity of operating conditions for each population.

3. Procedures will be revised to specify:

   a. Standpipe and system flow tests for hose stations at the hydraulically most limiting locations for each zone of the system on a five year interval to demonstrate the capability to provide the design pressure at required flow.

   b. Acceptance criteria for wet pipe main drain tests. Flowing pressures from test to test will be monitored to determine if there is a 10% reduction in full flow pressure when compared to previously performed tests. The Corrective Action Program will determine the cause and necessary corrective action.

   c. If a flow test or a main drain test does not meet acceptance criteria due to current or projected degradation additional tests are conducted. The number of increased tests is determined in accordance with the corrective action process; however, there are no fewer than two additional tests for each test that did not meet acceptance criteria. The additional inspections are completed within the interval in which the original test was conducted. If subsequent tests do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of tests. The additional tests include at least one test at the other unit with the same material, environment, and aging effect combination.

d. Main drains for the standpipes associated with hose stations within the scope of subsequent license renewal will also be added to main drain testing procedures.

4. Procedures will be revised to perform internal visual inspections of sprinkler and deluge system piping to identify internal corrosion, foreign material, and obstructions to flow. Follow-up volumetric examinations will be performed if internal visual inspections detect ~~age-related degradation in excess of what would be expected accounting for design, previous inspection experience, and inspection interval.~~an unexpected level of degradation due to corrosion product deposition. If organic or foreign material, or internal flow blockage that could result in failure of system function is identified, then an obstruction investigation will be performed within the Corrective Action Program that includes removal of the material, an extent of condition determination, review for increased inspections, extent of follow-up examinations, and a flush in accordance with NFPA 25, 2011 Edition, Annex D.5, Flushing Procedures. The internal visual inspections will consist of the following: (Relocated from Enhancement 10 and Corrected - Change Notice 2)

   a. Wet pipe sprinkler systems - 50% of the wet pipe sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote sprinkler, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. During the next five-year inspection period, the alternate systems previously not inspected shall be inspected.

   b. Pre-action sprinkler systems - pre-action sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.

   c. Deluge systems - deluge systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.

Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), and Monitoring and Trending (Element 5)

5. Procedures will be revised to perform system flow testing at flows representative of those expected during a fire. A flow resistance factor (C-factor) will be calculated to compare and trend the friction loss characteristics to the results from previous flow tests.

Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4)

~~6. Procedures for hydrant flushing will be revised to require fully opening the hydrant and fully flowing the hydrant for no less than one minute and until foreign material has cleared. In addition, procedures will be revised to observe draining of the hydrant barrel and also require~~

~~the barrel be pumped dry should it not drain within 60 minutes. Hydrants outside the protected area that are within the scope of subsequent license renewal will be added to the flush scope.~~

7. The *Fire Water System* program will be revised to periodically inspect the insulated exterior surfaces of the fire water tanks on a 10-year frequency during the subsequent period of operation. Insulation is removed to provide a minimum inspection population of 25 one-square foot samples. The samples will be distributed in such a way that inspections occur on the tank dome, near the tank bottom, at points where structural supports, pipe, or instrument nozzles penetrate the insulation and where water could collect. In addition, inspection locations will be based on the likelihood of corrosion under insulation occurring.

~~8. Procedures for mainline strainer flushing will be revised to require flushing until clear water is observed after each operation or flow test. In addition to flushing after operation, the Radwaste Facility mainline strainer will require an inspection every five years for damaged and corroded parts.~~

9. A procedure will be created to provide a Turbine Building oil deluge systems spray nozzle air flow test to ensure that patterns are not impeded by plugged nozzles, to ensure that nozzles are correctly positioned, and to ensure that obstructions do not prevent discharge patterns from wetting surfaces to be protected.

~~10. Procedures will be revised to perform internal visual inspections of sprinkler and deluge system piping to identify internal corrosion, foreign material, and obstructions to flow. Follow-up volumetric examinations will be performed if internal visual inspections detect age-related degradation in excess of what would be expected accounting for design, previous inspection experience, and inspection interval.an unexpected level of degradation due to corrosion product deposition. If organic or foreign material, or internal flow blockage that could result in failure of system function is identified, then an obstruction investigation will be performed within the Corrective Action Program that includes removal of the material, an extent of condition determination, review for increased inspections, extent of follow up examinations, and a flush in accordance with NFPA 25, 2011 Edition, Annex D.5, Flushing Procedures. The internal visual inspections will consist of the following:~~ (Relocated to Enhancement 4 - Change Notice 2)

~~Wet pipe sprinkler systems - 50% of the wet pipe sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote sprinkler, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. During the next five-year inspection period, the alternate systems previously not inspected shall be inspected.~~

~~Pre-action sprinkler systems – pre-action sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.~~

~~Deluge systems – deluge systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.~~

Detection of Aging Effects (Element4)

11. Procedure will be revised to provide inspection guidance related to lighting, distance and offset for non-ASME Code inspections. The procedure will specify adequate lighting be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two to four feet (or less) will be appropriate. For distant surface inspections, viewing aids such as binoculars may be used. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used.
12. The Unit 1 hydrogen seal oil system deluge sprinkler pipe and Unit 1 station main transformer '1A' deluge sprinkler piping will be reconfigured to allow drainage.
13. The program will be revised to require inspections and tests be performed by personnel qualified in accordance with site procedures and programs for the specified task.
14. Procedures will be revised to require when degraded coatings are detected by internal coating inspections, acceptance criteria and corrective action recommendations consistent with the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers and Tanks (B2.1.28) program are followed in lieu of NFPA 25 section 9.2.7 (1), (2), and (4). When interior pitting or general corrosion (beyond minor surface rust) is detected, tank wall thickness measurements are conducted as stated in NFPA 25 Section 9.2.7(3) in vicinity of the loss of material. Vacuum box testing as stated in NFPA 25 Section 9.2.7(5) is conducted when pitting, cracks, or loss of material is detected in the immediate vicinity of welds.

Detection of Aging Effects (Element4) and Acceptance Criteria (Element 6)

15. Procedures will be revised to address recurring internal corrosion with the use of Low Frequency Electromagnetic Technique (LFET) or a similar technique on 100 feet of piping during each refueling cycle to detect changes in the pipe wall thickness. LFET screening or a similar technique will also be performed on accessible interior fire water storage tank bottoms during periodic inspections. The procedure will specify thinned areas found during the LFET screening be followed up with pipe wall thickness examinations to ensure aging effects are managed and wall thickness is within acceptable limits. In addition to the pipe wall thickness examination, the performance of opportunistic visual inspections of the fire protection system will be required whenever the fire water system is opened for maintenance.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Fire Water System* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In January 2012, an Engineering walkdown of the fire protection piping header along the north wall of the Unit 2 Turbine Building revealed a potential leak location on the supply line to a hose rack. The flanged connection and straight pipe were removed and replaced.

2. In January 2012, a section of 2-inch fire protection "drop" piping in the Turbine Building developed a leak. The investigation for extent of condition and determination for the extent of fire protection piping to be inspected and replaced, as necessary, involved inspections of three locations in the Turbine Building and three locations in the Auxiliary Building. Microbiologically induced corrosion (MIC) was evident in many locations, but the extent of corrosion was not as severe in the Auxiliary Building as it was in the Turbine Building. Despite the less severe corrosion in the Auxiliary Building, the three segments of piping that were inspected were replaced. Similarly, one of the three segments of piping in the Turbine Building was replaced.

   A capital project was proposed for a multi-year process of replacing segments of 2-inch, 4-inch, and 10-inch piping in the Turbine Building. The initial phase that was completed included replacing 200 feet of ten inch piping in the Turbine Building. Additional phases were proposed, and described in the Fire Protection Strategic Plan. See April 2013 and November 2015 operating experience.

3. In June 2012, during inspection of Auxiliary Building fire protection piping minor sediment was discovered in the supply header to the Unit 1 cable tunnel sprinklers. Debris and MIC nodules were discovered inside a spool piece and accessible four inch piping. The sediment and debris were removed, the visual inspection was performed, and the blind flanges and spool pieces were replaced. The necessary pipe replacement is included in the Fire Protection Strategic Plan.

4. In March 2013, NRC Information Notice 13-06, "Corrosion in Fire Protection Piping Due to Air and Water Interaction", identified industry operating experience involving the loss of function of fire protection water systems due to the potential for adverse air and water interactions in pre-action and dry-pipe systems. Engineering evaluated the potential for similar adverse conditions and associated degradation in deluge systems at Surry Power Station that are periodically flow tested. Subsequently, in January 2018, a walkdown was performed to confirm that plant design specifications on drainage features for piping downstream of all in-scope pre-action and deluge valves in the fire protection system continued to be in effect. Two locations, one relating to main transformer 1A and one relating to Unit 1 generator hydrogen seal oil system, were identified as having a potential for adverse air and water interactions and entered into the corrective action program.

5. In April 2013, a section of two 10-inch fire protection system piping in the Turbine Building developed a leak. A walkdown of six locations was performed to determine extent of condition in the Turbine Building and the Auxiliary Building. MIC was evident in four locations, but the extent of corrosion in the Auxiliary Building was not as severe. Replacement of 4-inch and 10-inch fire protection header is a like-for-like replacement. The replacement of the Turbine Fire Protection Header was split into four different phases. One phase was to be accomplished each year. The second phase is planned to replace approximately 400 feet of ten-inch header pipe and 200 feet of two-inch hose station pipe. The necessary pipe replacement is included in the Fire Protection Strategic Plan.

6. In February 2014, visual and volumetric inspections were performed for Fire Protection/domestic water storage tank 1A to determine the extent of additional degradation that had occurred since similar inspections were completed in December 2008. The most significant degradation was noted on the tank floor. The result of the visual inspection was that coating degradation was continuing, and that some bare metal was evident. Similarly, volumetric examinations found additional thinning for the tank floor. An engineering evaluation projected that the tank floor plate would reach minimum acceptable thickness prior to the expiration of the Unit 2 renewed operating license. Monitoring of the tank floor will continue until the tank floor is repaired or replaced. The necessary tank repair or replacement is included in the Fire Protection Strategic Plan.

7. In August 2014, visual and volumetric inspections were performed for Fire Protection/domestic water storage tank 1B to determine the extent of additional degradation that had occurred since similar inspections were completed in December 2008. The most significant degradation was noted on the tank floor. The result of the visual inspection was that coating degradation was continuing, and that some bare metal was evident. Volumetric examinations found some thinning of the tank floor. An engineering evaluation projected that the tank floor plate would reach minimum acceptable thickness prior to the expiration of the Unit 2 renewed operating license. Monitoring of the tank floor will continue until the tank floor is repaired or replaced.

8. In September 2014, a materials analysis was performed on buried cement lined grey cast iron fire main piping that was fractured during flow testing of hose station valves. The fracture was attributed to a latent material defect in the cast iron. The piping was removed and replaced with an equivalent spool piece. Based on the oxidation along the top segment of the crack, the pipe was cracked for a long period of time. High levels of calcium deposits on the fracture (from the cement lining) indicate that the pipe was partially cracked at the top segment before factory installation of the cement liner (manufacturing process). Material analysis of the pipe determined that the microstructure consisted of graphite flakes that were approximately 75% ferrite and 25% pearlite. This resulted in a reduction in the supplied material hardness. Failure of pipe was not preventable through maintenance. The failure was caused by ground settling. During the pipe replacement it was observed that there was vertical misalignment between the replacement pipe and the existing buried pipe, which indicated that the buried side piping was exerting a large bending load at the anchor/foundation. This bending load along with the pre-existing crack and lower hardness value caused the pipe fracture. The balance of the failed pipe was found in good condition with no significant loss of cement lining material, corrosion, cracking, fouling, or reduction of pipe interior diameter.

9. In November 2015, an effectiveness review of the Fire Protection Program aging management activity (AMA) (UFSAR Section 18.2.7) was performed. The AMA was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. A comprehensive fire water system assessment recommended a large scale piping replacement of turbine building and auxiliary building piping. The large scale piping replacement project to be performed over multiple refueling outages was identified as a measure to address degradation in carbon steel system piping and to ensure that system intended functions were maintained. Completed and closed phases of this effort have included replacement of approximately 400 feet of 4 inch piping and 200 feet of 2 inch piping in 2014 and approximately 567 feet of 4 inch piping and 303 feet of 2 inch piping in 2015. An additional phase replacing approximately 175 feet of 4 inch piping and 100 feet of 2 inch piping has been completed and is awaiting final testing. Work documents for additional phases are planned and issued for work extending into 2019.

10. In April 2016, results from fire protection system flow tests with the motor driven fire pump in April 2016, July 2013, and April 2010 consistently showed that the system pressure is higher than the required value for the corresponding flow rate. In 2016, the result indicated that the measured pressure exceeded the required pressure by fourteen psi. In 2013, the measured pressure was thirteen psi higher than required. The result in 2010 measured a pressure that was 19 psi higher than required. The trend from these results does not indicate significant degradation over the six-year interval, particularly considering the two most recent measurements. There is confidence that continued implementation of flow monitoring for the fire protection system using the three year interval required by the Technical Requirements Manual will effectively manage aging prior to a loss of intended function.

11. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.
12. In November 2017, as part of oversight reviews of the Fire Protection Program AMA (UFSAR Section 18.2.7), an inconsistency was identified in the performance interval for system integrity demonstration by main drain testing. The test interval had been extended from quarterly to each 18 months but the extended interval had not been incorporated into program documents. An Engineering Assignment to review operating experience to trended performance data to 2011 has been completed with no significant degrading trends observed. The new interval is consistent with the test interval of NFPA 25 (2011 Edition) Table 13.1.1.2 modified by NUREG-2191, Section XI.M27, Table XI.M27-1, Note 10.
13. In January 2018 an aging management program effectiveness review was performed for the Fire Protection Program AMA (UFSAR Section 18.2.7). Information from the summary of that effectiveness review is provided below:

    The Fire Protection Program AMA is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. Key activities of the Fire Protection Program AMA that were reviewed include the inspection of components, the evaluation of inspection results, repairs/replacements, corrective actions, and AMA document updates. Engineering reports from 2006 to 2017 of inspections results were reviewed to confirm inspection frequencies were conducted at appropriate intervals and corrective actions taken consistent with the observed aging degradation. The review also included pertinent issues found in the Corrective Action Program from 2006 through 2017 for age related degradation of fire protection components within the scope of license renewal.

    In the past, multiple fire water piping leaks had been identified in the Unit 1 and Unit 2 Turbine Buildings. As a result, a five phase large scale fire protection piping replacement project has been underway since 2015 to replace Turbine Building header piping and hose station piping as well as the Unit 1 and Unit 2 Auxiliary Building Hose station piping. Two of the Turbine Building phases are complete and two are waiting on testing. Phase five includes the remaining scope in the turbine building and the entire scope in the Auxiliary Building and is planned to start in 2018. Once complete, a large majority of the above ground fire protection piping in the plant will have been replaced, including areas where reoccurring leaks were previously identified.

The fire water/domestic water storage tanks are managed by the Tank Inspection Activities AMA (UFSAR Section 18.1.3); but, are also discussed here for overall fire protection performance considerations. The fire water/domestic water storage tanks were found to have failing internal coatings and loss of material on the tank floors. Estimates for projected useable tank lifetime and evaluations for additional monitoring were performed. Recommendations are being prepared for repair or replacement project considerations.

Multiple operating issues, and obsolescence of the diesel driven fire pump resulted in a design change that replaced the diesel driven fire pump and associated control panel. The new diesel driven fire pump has exhibited substantially improved performance compared to the original fire pump.

Activities to implement NFPA 25, 1998 Edition, Section 2-3.1.1 (1998 edition), testing of sprinklers that have been in service for fifty years have been initiated to prove continued functionality. The Unit 1 and Unit 2 turbine building sprinklers have been sampled and will be tested by 2021, when fifty years of service is reached.

Recurring Internal Corrosion (RIC)

Recurring internal corrosion, including through-wall failures due to microbiological induced corrosion, has occurred on several occasions. Periodic fire protection system piping flushes, flow testing and piping thickness measurements will be performed to identify pipe degradation prior to loss of system intended function. Periodic visual inspections and tank bottom thickness measurements are performed on the fire water storage tanks. In addition to recent piping replacements in the Turbine Building and the Auxiliary Building to address instances of RIC due to microbiologically-influenced corrosion, Low Frequency Electromagnetic Technique (LFET) or a similar technique on 100 feet of piping during each refueling cycle to detect changes in the pipe wall thickness. LFET screening or a similar technique will also be performed on accessible interior fire water storage tank bottoms during periodic inspections. Thinned areas found during the LFET scan are followed-up with pipe wall thickness examinations to ensure aging effects are managed and that wall thickness is within acceptable limits. In addition to the pipe wall thickness examination, opportunistic visual inspections of the fire protection system will be performed whenever the fire water system is opened for maintenance.

The above examples of operating experience provides objective evidence that the *Fire Water System* program includes activities to perform periodic fire main and hydrant inspections and flushing, sprinkler inspections, functional test, and flow tests to identify loss of material, flow blockage, and loss of coating integrity for in-scope water-based fire protection systems within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Fire Water System* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Appropriate guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Fire Water System* program, following enhancement, will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

The continued implementation of the *Fire Water System* program, following enhancement, will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.18 Fuel Oil Chemistry

Program Description

The *Fuel Oil Chemistry* program is an existing mitigative and condition monitoring and preventive program that manages loss of material and reduction of heat transfer from tanks, piping, and components in a fuel oil environment. The program includes activities which provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of subsequent license renewal.

The fuel oil tanks within the scope of subsequent license renewal include:

- Underground Fuel Oil Storage Tanks
- AAC Diesel Generator Fuel Oil Tank
- Emergency Service Water Pump Fuel Oil Tank
- Emergency Diesel Generator (EDG) Auxiliary Fuel Oil Tanks
- Diesel Fire Pump Fuel Oil Tank
- Security Diesel Generator Fuel Oil Tank
- EDG Fuel Oil Base Tanks

The fuel oil storage tanks within the scope of subsequent license renewal do not have internal coatings or linings, with the exception of the security diesel generator fuel oil tank, which is provided with a solvent-based rust preventive film (not considered a coating). The fuel oil tanks within the scope of subsequent license renewal are maintained by monitoring and controlling fuel oil contaminants in accordance with ~~Technical Specifications,~~ the Technical Requirements Manual~~,~~ and ASTM standards. Fuel oil sampling and analysis is performed in accordance with approved procedures for new fuel oil and stored fuel oil.

The program samples fuel oil using the guidelines of the following ASTM standards, as well as additional ASTM standards:

- ASTM D 975-74, "Standard Specification for Diesel Fuel Oils"
- ASTM D 4057-95, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products"
- ASTM D 6217-98, "Standard Test Method for Particulate Contamination in Middle Distillate Fuels by Laboratory Filtration"
- ASTM D 1796-83, "Standard Test Method for Water and Sediment in Fuel Oil by the Centrifuge Method"

Fuel oil tanks are periodically drained of water and accumulated sediment, cleaned, and internally inspected when accessible. These activities effectively manage the effects of aging by maintaining potentially harmful contaminants at low concentrations. Where internal cleaning and inspection are not physically possible, bottom thickness measurements of inaccessible tanks are performed in lieu of cleaning and internal inspection. Tanks that cannot be cleaned and internally inspected, and are physically inaccessible for bottom thickness measurements, are monitored for leakage consistent with the current licensing basis. Corrective actions require water to be removed from fuel oil storage tanks when detected and the condition entered in the Corrective Action Program. Additionally, when biological activity is confirmed, or there is evidence of internal tank corrosion, Chemistry evaluates the need to add a biocide to the fuel oil.

The *One-Time Inspection* program (B2.1.20) will be used to verify the effectiveness of the *Fuel Oil Chemistry* program.

NUREG-2191 Consistency

The *Fuel Oil Chemistry* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI.M30, Fuel Oil Chemistry.

Exception Summary

The following program element(s) are affected:

Preventive Actions (Element 2), Parameters Monitored/Inspected (Element 3), Detection of Aging Effects (Element 4), Monitoring and Tending (Element 5) and Acceptance Criteria (Element 6)

1. NUREG-2191 refers to various cleaning and inspection activities associated with fuel oil storage tanks within the scope of subsequent license renewal. The security diesel generator fuel oil tank and the EDG fuel oil base tanks cannot be cleaned internally and are not accessible for internal inspection or bottom thickness measurements. The basis for exceptions to these requirements is provided below.

<u>Justification for Exception</u>

The security diesel generator fuel oil tank is a heavy gauge steel, 300 gallon, double walled base tank with a leak detection monitor in the annulus between ~~the~~ two tanks. <u>The</u> ~~Interior~~ wall~~s~~ of the <u>interior</u> tank <u>is</u> ~~are~~ provided with a solvent-based rust preventive film (not considered a coating). The <u>fuel oil</u> tank is mounted directly below the security diesel. Internal cleaning and inspection, as well as bottom thickness measurements, are not physically possible due to the design and location of the <u>fuel oil</u> tank. In lieu of these requirements, the integrity of the inner tank will be monitored by the leak detection instrumentation, which actuates an alarm locally in the Central Alarm Station (CAS) Diesel Generator Room. <u>The security diesel generator fuel oil tank is constructed to meet the requirements of UL142. As required by UL142, the outer tank is constructed so that liquid can flow freely within the interstitial space between the inner and outer tanks to a collection point for</u>

monitoring. A leak detector is located near the bottom in the annulus between the inner tank and the outer tank such that leakage would result in an alarm. In order to avoid false leak alarms resulting from sweating of the tank, the leak detector in the annulus area is not typically placed directly on the outer tank floor, but is offset by about 1 inch. Based on tank drawings, leakage resulting in a 1 inch depth would represent a loss of less than 10% of the inner tank total volume. At least once daily, Operators enter each CAS Diesel Generator Room, perform visual inspections and record the level reading in the security diesel generator fuel oil tank. Operators are required to check for leakage from components in the CAS Diesel Generator Room. As required by procedures, operators notify the control room in a timely manner of any abnormal conditions. The security diesel generator fuel oil tank is a relatively shallow tank that is vented. Therefore, any corrosion of the inner tank resulting in through wall leakages would result in a slow leak into the tank annulus which would be identified by an alarm or during operator rounds prior to an appreciable loss of inventory. Conditions found to impact the function of the security diesel generator fuel oil tank will be documented and entered into the Corrective Action Program. Based on the above, there is reasonable assurance that degradation of the security diesel generator fuel oil tank would be identified prior to a loss of intended function to maintain an inventory of fuel oil for security diesel generator operation.

The EDG fuel oil base tanks are fabricated from carbon steel. These 550 gallon tanks are located directly beneath each EDG and cannot be ~~fully and generally~~ accessed for cleaning, internal inspections, or tank bottom thickness measurements. ~~Each base tank is provided with level instrumentation, which actuates an alarm in the Control Room on decreasing level. At least twice daily, operators enter each EDG Room to record EDG fuel oil base tank levels and perform visual inspections. Station Logs require operators check for leakage from components in the EDG Rooms, including the EDG fuel oil base tanks.~~ Prior to the subsequent period of extended operation, a one-time inspection will be performed on the accessible internal surfaces on one EDG fuel oil base tank~~ at SPS~~. Inspection will be limited due to the restricted accessibility through the tank sampling port. A visual inspection will be performed using a boroscope or equivalent instrument which will provide information regarding tank degradation on the accessible internal surfaces. In addition, each base tank is provided with level instrumentation, which on decreasing level automatically starts transferring fuel oil from the EDG auxiliary fuel oil tanks to the EDG base tanks and actuates an alarm in the Control Room. At least twice daily, operators enter each EDG Room, record EDG fuel oil base tank levels and perform visual inspections. As required by procedure operators check for leakage from components in the EDG Rooms, including the EDG fuel oil base tanks. Operators notify the control room in a timely manner of any abnormal conditions. The EDG fuel oil base tanks are relatively shallow tanks that are vented. Therefore, any corrosion resulting in through wall leakages would result initially in a slow leak that would be identified prior to an appreciable loss of inventory. Conditions found to impact the function of an EDG fuel oil base tank will be documented and entered into the Corrective Action Program. Based on the above, there is reasonable assurance that degradation of the EDG fuel oil base tank would be identified prior to a loss of intended function to maintain an inventory of fuel for EDG operation.~~an acceptable level of information regarding tank degradation on the accessible internal surfaces.~~

Enhancements

Prior to entering the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Scope of Program (Element 1)

1. Procedures will be revised to include the emergency diesel generator (EDG) fuel oil base tanks within the scope of the *Fuel Oil Chemistry* program.

Parameters Monitored/Inspected (Element 3)

2. Existing procedures will be revised to include a requirement for quarterly sampling of the EDG auxiliary fuel oil tanks and EDG fuel oil base tanks for particulates and water.

Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5), and Acceptance Criteria (Element 6)

3. Procedures will be revised to require the following fuel oil storage tanks within the scope of subsequent license renewal be drained, cleaned, and the internal surfaces visually inspected for degradation within ten years of entering the subsequent period of extended operation, and every ten years during the subsequent period of extended operation:
   - Underground fuel oil storage tanks
   - AAC diesel generator fuel oil tank

   If degradation is found during the internal visual inspection, bottom thickness measurements will be performed. Visual and volumetric examinations will be performed by personnel qualified in accordance with the standards of the American Petroleum Institute.

4. Procedures will be developed to perform periodic bottom thickness measurements of the following tanks within ten years of entering the subsequent period of extended operation, and every ten years during the subsequent period of extended operation:
   - EDG auxiliary fuel oil tanks
   - Diesel fire pump fuel oil tank
   - Emergency service water pump fuel oil tank

   Volumetric examinations will be performed by personnel qualified in accordance with the standards of the American Petroleum Institute.

5. Procedures will be developed to require an engineering evaluation be performed to document, evaluate, and trend visual and volumetric (as applicable) inspection results for the following fuel oil storage tanks:

   - Underground fuel oil storage tanks
   - AAC diesel generator fuel oil tank
   - EDG auxiliary fuel oil tanks
   - Diesel fire pump fuel oil tank
   - Emergency service water pump fuel oil tank

   The procedures will require unacceptable inspection results, as determined in the engineering evaluation, be documented in the Corrective Action Program. Bottom thickness measurements will be required to be evaluated against the design thickness and corrosion allowance. The frequency ~~between~~of future inspections will not be allowed to be reduced if bottom thickness measurements indicate the corrosion allowance will be exceeded prior to the next scheduled inspection.

   If a tank does not have a stated corrosion allowance, the tank will be evaluated for acceptability in the engineering evaluation. The engineering evaluation will evaluate the need to reduce the time period between future inspections based on inspection results.

Detection of Aging Effects (Element 4), and Acceptance Criteria (Element 6)

6. Prior to the subsequent period of extended operation, a one-time inspection will be performed on the accessible internal surfaces on one EDG fuel oil base tank at SPS. Inspection will be limited due to the restricted accessibility through the tank sampling port. A visual inspection will be performed using a boroscope or equivalent instrument which will provide an acceptable level of information regarding tank degradation on the accessible internal surfaces.

Corrective Action (Element 7)

7. Procedures will be revised to require a biocide be added when biological activity is detected or if there is evidence of tank internal corrosion.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Fuel Oil Chemistry* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In 2005, the underground fuel oil storage tanks were drained, internal surfaces cleaned, and wall thickness measurements performed by certified American Petroleum Institute inspectors. The tanks were found to be in excellent condition with no detectable loss of material.

2. Between 2007 and 2011, API-653, "Tank Inspection, Repair, Alteration, and Reconstruction," in-service inspections were performed on the following fuel oil storage tanks, consistent with commitments made for initial license renewal:

    - AAC diesel generator fuel oil tank
    - Emergency service water pump fuel oil tank
    - Emergency diesel generator (EDG) auxiliary fuel oil tanks
    - Diesel fire pump fuel oil tank

    The inspections included recording of tank wall thicknesses as well as external visual inspections of fuel oil tanks within the scope of initial license renewal. Each tank was found to be in acceptable condition with inspection results documented in an engineering evaluation.

3. In 2010, during quarterly sampling of the diesel fire pump fuel oil tank, approximately 0.25 inches of water was detected in the tank and was subsequently removed from the tank. A follow-up engineering walkdown revealed the tank flame arrestor rain cover was damaged and was the apparent cause for water entering the tank. The flame arrestor was replaced approximately two weeks later. The next quarterly sample did not identify the presence of water in the tank.

4. In 2013, quarterly sampling identified the presence of sediment in the diesel fire pump fuel oil tank when the sampling device contacted the wall of the tank during routine sampling. It was believed that the cause of the condition may have been the result of water entering the tank through the damaged flame arrestor cover in 2010. A work order was initiated to clean the tank internal surfaces. After cleaning, rust scale on the internal surfaces of the tank remained. The internal corrosion prompted replacement of the tank in 2014.

5. In 2013, routine sampling identified 0.25 inches of water in a underground fuel oil storage tank. A second sample confirmed the presence of water. Additional analysis was performed to confirm the absence of bacteria. The subsequent routine sample of the underground fuel oil storage tank did not identify the presence of water in the tank.

6. In 2015, wall thickness measurements were performed on two fuel oil lines. Both lines exhibited approximately two mils of wastage. The wall thickness as measured was well above the minimum acceptable wall thickness and evaluated as satisfactory by Engineering.

7. In 2015, during routine quarterly sampling, particulates were identified in one of the two underground fuel oil storage tanks that exceeded the acceptance criteria. A follow-up sample showed tank particulate values were acceptable, but still elevated. Work orders were initiated to recirculate and filter both underground tanks. Particulate levels were restored to values well below the acceptance criteria. Post filtration samples taken over a two day period showed particulates levels had increased by approximately two mg/L. Additional samples were

performed and sent to two off-site laboratories for independent analysis and verification. The particulate values reported from one off-site lab were approximately three mg/L higher than the second off-site lab. Chemistry personnel verified both labs were conducting the tests to the correct ASTM standard (i.e., ASTM D6217-98). The only difference noted was the two off-site labs used filters from different manufacturers. Both filters provided acceptable results, but one filter indicated particulates of two to three mg/L higher than the second filter.

8. In December 2015, an effectiveness review of the Fuel Oil Chemistry Activity (UFSAR Section 18.2.8) was performed. The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. No gaps were identified by the effectiveness review.

9. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.

10. In January 2018, an AMP effectiveness review was performed of the Fuel Oil Chemistry Activity (UFSAR Section 18.2.8). Information from the summary of that effectiveness review is provided below:

    The Fuel Oil Chemistry Activity is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. Key activities of the that were reviewed include the scope of the diesel fuel oil tanks managed by the activity, the consistency of sample analyses and techniques with established industry guidance, and a review of pertinent issues found in the Corrective Action Program from 2006 to 2017 for age-related degradation of components exposed to the fuel oil environment.

    The aspects of the AMA reviewed include station procedures and their relationship to industry guidelines which include the EPRI Report No. 1015061, "Guide for the Storage and Handling of Fuel Oil for Standby Diesel Generator Systems". The AMA is managed in accordance with industry best practices and results do not reveal any loss of intended function as a result of aging. Pertinent issues found in the Corrective Action Program from 2006 through 2017 related to diesel fuel oil were reviewed and determined to be satisfactorily resolved without any further issues.

The Fuel Oil Chemistry Activity ensures that stored diesel fuel oil is within specifications required for proper operation of the station's safety-related diesel engines, in order to prevent unanticipated equipment failure due to fuel oil-related issues. Departures from fuel oil specifications for particulates and water have been infrequent and quickly returned to within limits. For example, in 2015, routine sampling of the Emergency Diesel Generator (EDG) Fuel Oil Storage Tanks (FOSTs) identified rising particulate levels in both EDG FOSTs. Backup samples confirmed elevated particulate levels in the fuel oil. Both tanks were recirculated and filtered to reduce particulate levels to acceptable levels within two days. Additional samples were drawn and sent to an offsite laboratory to confirm the return of diesel fuel oil to specifications.

The above examples of operating experience provides objective evidence that the *Fuel Oil Chemistry* program includes activities to perform control of chemistry parameters in to manage loss of material and reduction of heat transfer (due to fouling) and to perform visual inspection of tanks, and thickness measurements of tank bottoms to identify loss of material for fuel oil tanks within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Fuel Oil Chemistry* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Fuel Oil Chemistry* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Fuel Oil Chemistry* program, following enhancement, will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.25 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

Program Description

The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program is an existing condition monitoring program that manages loss of material, cracking, reduction of heat transfer, and flow blockage of metallic components. The program also manages hardening or loss of strength, loss of material, cracking or blistering, and flow blockage of polymeric components. This program consists of visual inspections of accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components, and other components exposed to air, condensation, diesel exhaust, fuel oil, lubricating oil, and any water environment. Aging effects associated with items (except for elastomers) within the scope of the *Open-Cycle Cooling Water System* program (B2.1.11), *Closed Treated Water Systems* program (B2.1.12), and *Fire Water System* program (B2.1.16) are not managed by this program.

Inspections of metallic components monitor for visible evidence of loss of material. Indicators of aging effects for metallic components include corrosion and surface imperfections; loss of wall thickness; flaking or oxide-coated surfaces; debris accumulation on heat exchanger tube surfaces; and accumulation of particulate fouling, biofouling, or macro fouling.

ASME Code, Section XI visual (VT-1) examinations or surface examinations will be conducted to detect cracking of stainless steel, aluminum, ~~and~~ copper alloy (>15% Zn), and Grade 2 titanium components.

Inspections of polymeric and elastomeric components monitor for changes in material properties or loss of material. Indicators of loss of material and changes in material properties include surface cracking, crazing, scuffing, loss of sealing, dimensional change, loss of wall thickness, discoloration, exposure of internal reinforcement, hardening, and blistering. Physical manipulation or pressurization will be used to augment the visual examinations conducted under this program in order to detect hardening or loss of strength.

The internal inspections are performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. At a minimum, in each 10-year period during the subsequent period of extended operation, a representative sample of 20% of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of nineteen components per population at each unit will be inspected.

Where the sample size is not based on the percentage of the population, it is acceptable to reduce the total number of inspections to nineteen components per population at each unit. The reduced total number of inspections is acceptable because the operating conditions and history at each unit are sufficiently similar (e.g., flowrate, chemistry, temperature, excursions) such that aging effects are not occurring differently between the units. Past power up-rates were implemented for both units at approximately the same time. Historically, water chemistry conditions between the two units have been very similar. The raw water source for both units is the James River. Emergency diesel generator runs are managed to equalize total run times among the diesels, so as to equalize wear and aging. Operating experience for each unit demonstrates no significant difference in aging effects of systems in the scope of this program between the two units.

If any inspections do not meet the acceptance criteria, additional inspections will be conducted, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (i.e., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the next refueling outage interval.

Where practical, the inspections will focus on the bounding or lead components most susceptible to aging because of time in-service, and severity of operating conditions. Opportunistic inspections will continue in each period even if the minimum number of inspections has been conducted.

Inspections are performed by personnel qualified in accordance with procedures and programs to perform the specified task. Inspections within the scope of the ASME Code will follow procedures consistent with the ASME Code. Non-ASME Code inspection procedures will include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the subsequent period of extended operation. For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions.

NUREG-2191 Consistency

The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Parameters Monitored/Inspected (Element 3) and Detection of Aging Effects (Element 4)

1. Procedures will be revised to require inspection of metallic components for flaking or oxide-coated surfaces.
2. Procedures will be revised to require inspection of elastomeric and flexible polymeric components for the following:
   a. Surface crazing, scuffing, loss of sealing, blistering, and dimensional change (e.g., "ballooning" and "necking")
   b. Loss of wall thickness
   c. Exposure of internal reinforcement (e.g., reinforcing fibers, mesh, or underlying metal) for reinforced elastomers
3. Procedures will be revised to specify that visual inspection of elastomeric and flexible polymeric components is supplemented by tactile inspection to detect hardening or loss of suppleness. The minimum surface area for tactile inspections will be at least 10% of the accessible surface area.

Detection of Aging Effects (Element 4)

4. Procedures will be revised to provide non-ASME Code inspection guidance related to lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. The procedure will specify adequate lighting be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two feet or less will be appropriate. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used. For internal inspections, accessible surfaces will be inspected. If inspecting piping internal surfaces, a minimum of one linear foot will be inspected, if accessible. Cleaning will be performed, as necessary, to allow for a meaningful examination. If protective coatings are present, the procedure will require the condition of the coating to be documented.
5. <u>Procedures will be revised to specify that follow-up volumetric examinations are performed where irregularities that could be indicative of an unexpected level of degradation are detected for steel components exposed to raw water, raw water (potable), or waste water.</u>

6. A new procedure will be developed to specify that in each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed for the various sample populations (each material, environment, and aging effect combination). If opportunistic inspections will not fulfill the minimum number of inspections by the end of each 10-year period, the program owner will initiate work orders as necessary to request additional inspections. A representative sample of 20% of the population (defined as components having the same material, environment, and aging effect combination) or a maximum of nineteen components per population at each unit will be inspected. The new procedure will specify that the inspections focus on the bounding or lead components most susceptible to aging due to time in service and severity of operating conditions.

Monitoring and Trending (Element 5) and Acceptance Criteria (Element 6)

7. A new procedure will be developed to evaluate and project the rate of any degradation until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection sampling bases (e.g., selection, size, frequency) will be adjusted as necessary based on the projection.

Acceptance Criteria (Element 6)

8. A new procedure will be developed to specify that, where practical, acceptance criteria are quantitative (e.g., minimum wall thickness). For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions.

Corrective Actions (Element 7)

9. A new procedure will be developed to specify that additional inspections will be performed if any sampling-based inspections do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination are inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the next refueling outage interval.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In January 2009, a leak was identified in a raw water vacuum priming elbow servicing a Unit 1 component cooling heat exchanger. The condition was determined to be pitting due to microbiologically induced corrosion (MIC). The pipe section was removed and replaced. A separate condition report written at the same time documented another leak at a different location in the same section of piping. Three separate through wall leaks were noted on this section of piping and documented on the two condition reports. To provide more information as to extent of condition, another section of vacuum priming pipe on a different component cooling heat exchanger was removed, and showed evidence of MIC, although not through wall. Engineering recommended creation of preventive maintenance items to replace the vacuum priming piping with similar configuration to the MIC-damaged sections on the four Unit 1 component cooling heat exchangers every ten years to prevent future through wall leaks. The new preventive maintenance items were approved in October 2010.
2. In March 2012, during performance of a preventive maintenance activity, it was identified that the housing for an air handling unit was degraded. The internal condition of the housing showed corrosion of the metal. The unit was subsequently replaced as part of a design change to rectify persistent ventilation degradation and equipment obsolescence issues. The design change replaced the major mechanical components of the Unit 1 and Unit 2 cable spreading room ventilation systems and repaired associated ductwork.
3. In May 2013, Engineering performed non-destructive examination on a length of Unit 2 recirculation spray heat exchanger service water vent piping. An elbow in the length of piping showed significant wall thinning. This piping is vented to atmosphere, but is temporarily fully wetted with service water when flow testing the recirculation spray heat exchangers. Quarterly ultrasonic testing of the piping was performed to monitor the progression of thinning until the piping was replaced in the next outage. Inspection during the replacement of the piping documented exfoliation due to corrosion. This is an example of recurring internal corrosion in the service water system.

4. In May 2015, discharge piping in the Unit 1 Turbine Building from plumbing system sump pumps was identified to have several leaks at a threaded fitting at a rate of four to five gallons per minute. The fitting material is cast iron exposed to waste water. The sump liquid pH was determined to be neutral, so the cause was attributed to corrosion from stagnant water over time. Other recent examples of leaks in plumbing system piping at fittings have also been noted. Soft patch repairs were made to the leaks, and work orders initiated to replace the piping. This is an example of recurring internal corrosion in the plumbing system.

5. In December 2015, an effectiveness review was performed of the Work Control Process Activity (UFSAR Section 18.2.19). The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience activity elements. A sample of completed as-found inspection forms was reviewed and identified that the documentation of as-found inspections was inconsistent and needed improvement.

   As a corrective action, training of mechanical maintenance personnel on expectations for properly documenting as-found conditions was conducted. An additional corrective action that recommended enhancement of the as-found inspection form was closed administratively. This operating experience is revisited in the January 2018 AMP effectiveness review. Due to the need for additional improvements noted during the January 2018 AMP effectiveness review, a condition report was entered into the Corrective Action Program.

6. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

7. In November 2017, as part of oversight review activities, the Work Control Process Activity (UFSAR Section 18.2.19) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

8. In January 2018, an aging management program effectiveness review was performed of the Work Control Process Activity (UFSAR Section 18.2.19). Information from the summary of that effectiveness review is provided below:

   The Work Control Process Activity plans and conducts testing and maintenance activities, both preventive and corrective. Visual inspections are conducted of the internal surfaces of plant components and adjacent piping that are in the scope of license renewal to monitor for aging effects such as cracking and loss of material. Potential age-related degradation conditions are recorded on "as-found" inspection forms and dispositioned as necessary in the Corrective Action Program. A review was performed of station operating experience identified via the Work Control Process Activity, including conditions identified in the Corrective Action Program from 2006 through 2017.

   While the automatic inclusion of the as-found inspection form in work packages ensures that inspections are performed on in-scope components, a review of a sampling of completed inspection forms throughout the period from 2006 to 2017 showed that inspection personnel are not consistent in the level of detail provided on the form when recording observed conditions. A self-assessment of the License Renewal program documented the issue of inconsistent level of detail on as-found inspection forms in 2015. This operating experience is discussed in item number five above. Corrective actions completed as a result of this Condition Report do not appear to have been effective.

   A sample of as-found inspection forms from March to June 2017 (after the corrective actions were completed) was reviewed and contained the following typical discrepancies:

   - Condition Report numbers not appropriately documented on the inspection sheets concerning discovered aging effects
   - Aging effects not described in detail and documented in the inspection sheet notes section
   - Aging effects table not filled out adequately
   - License Renewal inspection sheets inappropriately dispositioned

   To improve program effectiveness, the following will be addressed and documented during the next aging management program effectiveness review:

   - Investigation and evaluation of inspection results and corrective actions from a sample population of License Renewal equipment work orders
   - Clarification of procedural guidance on inspection parameters including documentation of aging effects
   - Re-training of inspection personnel (current staffing and maintenance of this population of inspectors)
   - Re-training of personnel reviewing inspection forms (current staffing and maintenance of this population of reviewers)

A condition report has been generated in the Corrective Action Program to document and track implementation of these corrective action

Recurring Internal Corrosion (RIC)

Recurring internal corrosion, including through-wall failures due to pitting and general corrosion, has been observed in the service water and plumbing systems. Occurrences in the service water system have been noted over a period from 2007 to 2013. Occurrences in the plumbing system have been noted over a period from 2011 to 2018. Corrective actions have been taken previously, and additional actions have been initiated as noted below to minimize the likelihood of piping and component degradation due to pitting and general corrosion in systems monitored by the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program (B2.1.25). Future occurrences of RIC will be documented in accordance with the Corrective Action Program.

Corrective actions include:

- Sections of service water piping not within the scope of GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment," that have documented leaks in the past due to corrosion of carbon steel from a raw water environment have been replaced. Opportunistic inspections of susceptible piping and components will be performed when the system boundary is opened. Periodic system walkdowns in accordance with plant procedure will monitor for leakage. Additional corrective actions will be determined via the Corrective Action Program if significant loss of material is detected.
- Work orders have been created to replace affected portions of the plumbing system piping along an approximately 77 foot length in the Unit 1 Turbine Building basement that have documented leaks from corrosion due to stagnant water in the lines. Opportunistic inspections of susceptible piping and components in other portions of the system within the scope of subsequent license renewal will continue to be performed when the system boundary is opened.

Recurring internal corrosion has also been observed in various lined or coated components, such as the main condenser channel heads and the 96 inch circulating water discharge piping. The aging effects of internally coated/lined surfaces are managed by the *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28). Specific operating experience examples and corrective actions that discuss such aging effects are documented in the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program.

The above examples of operating experience provide objective evidence that the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program includes activities to perform opportunistic inspections to identify loss of material, cracking, reduction of heat transfer, and flow blockage of metallic components. The program also includes activities to perform opportunistic inspections to identify hardening or loss of strength, loss of material, cracking or blistering, and flow blockage of polymeric components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program, following enhancement, will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.27 Buried and Underground Piping and Tanks

Program Description

The *Buried and Underground Piping and Tanks* program is an existing condition monitoring program that manages loss of material, blistering, and cracking on external surfaces of piping and tanks in soil or underground environments within the scope of subsequent license renewal through preventive and mitigative actions. The program addresses piping and tanks composed of steel, stainless steel, copper alloys, fiberglass reinforced plastic, and concrete. Depending on the material, preventive and mitigative techniques include external coatings, cathodic protection (CP), and the quality of backfill. Direct visual inspection quantities for buried components are planned using procedural categorization criteria. Transitioning to a higher number of inspections than originally planned is based on the effectiveness of the preventive and mitigative actions. Also, depending on the material, inspection activities include electrochemical verification of the effectiveness of cathodic protection, non-destructive evaluation of pipe or tank wall thicknesses, performance monitoring of fire mains, and visual inspections of the pipe from the exterior.

The buried carbon steel piping of the fuel oil system for emergency electrical power system is the only buried piping that is protected by an active CP system. Monthly periodic inspections confirm CP system availability and annual CP surveys are conducted to assess the effectiveness of the CP system. The program uses the -850 mV relative to CSE (copper/copper sulfate reference electrode), instant off criterion specified in NACE SP0169 for acceptance criteria for steel piping and tanks and determination of cathodic protection system effectiveness in performing cathodic protection surveys. The program includes an upper limit of -1200 mV on cathodic protection pipe-to-soil potential measurements of coated pipes to preclude potential damage to coatings. For steel components, where the acceptance criteria for the effectiveness of the cathodic protection is other than -850 mV instant off, loss of material rates are measured.

The balance of piping and tanks within the scope of subsequent license renewal are not provided with CP. Based on soil sampling and testing, it has been determined that installation and operation of CP is not necessary. Soil sampling and testing is performed during each excavation and a station-wide soil survey is also performed once in each 10-year period to confirm that the soil environment of components within the scope of license renewal is not corrosive for the installed material types. Soil sampling and testing is consistent with EPRI Report 3002005294, "Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants."

External inspections of buried components within the scope of subsequent license renewal will occur opportunistically when they are excavated for any reason.

Inspections are conducted by qualified individuals. Where the coatings, backfill or the condition of exposed piping does not meet acceptance criteria such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is extrapolated to the end of the subsequent period of extended operation, the sample size is increased.

As an alternative to performing visual inspections of the buried fire protection system components, monitoring the activity of the jockey pump is performed by the *Fire Water System* program (B2.1.16). The water-based fire protection system is normally maintained at required operating pressure and is monitored such that a loss of system pressure is detected and corrective action initiated.

The *Selective Leaching* program (B2.1.21) is applied in addition to this program to manage selective leaching for applicable materials in soil environments.

NUREG-2191 Consistency

The *Buried and Underground Piping and Tanks* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M41, Buried and Underground Piping and Tanks.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program elements:

Preventive Actions (Element 2)

1. Procedures will be revised to establish an upper limit of -1200mV for pipe-to-soil potential measurements of coated pipes so as to preclude potential damage to coatings.

~~Parameters Monitored/Inspected (Element 3), Detection of Aging Effects (Element 4) and Acceptance Criteria (Element 6)~~

~~2. Procedures will be revised to include visual inspection requirements and acceptance criteria for:~~

   ~~a. Absence of cracking in fiberglass reinforced plastic components and evaluation of blisters, gouges, or wear~~

   ~~b. Minor cracking and loss of material in concrete or cementitious material provided there is no evidence of leakage exposed or rust staining from rebar or reinforcing "hoop" bands~~

Acceptance Criteria (Element 6)

3. Procedures will be revised to specify that cathodic protection surveys use the -850mV polarized potential, instant off criterion specified in NACE SP0169-2007 for steel piping acceptance criteria unless a suitable alternative polarization criteria can be demonstrated. Alternatives will include the -100mV polarization criteria, -750mV criterion (soil resistivity is less than 100,000 ohm-cm), -650mV criterion (soil resistivity is greater than 100,000 ohm-cm), or verification of less than 1 mpy loss of material rate. Alternatives will be demonstrated to be effective through verification of soil resistivity every five years, use of buried coupons, electrical resistance probes, or placement of reference cells in the immediate vicinity of the piping being measured. As an alternative to verifying the effectiveness of the cathodic protection system every five years, soil resistivity testing is conducted annually during a period of time when the soil resistivity would be expected to be at its lowest value (e.g., maximum rainfall periods). Upon completion of ten annual consecutive soil samples, soil resistivity testing can be extended to every five years if the results of the soil sample tests consistently have verified that the resistivity did not fall outside of the range being credited (e.g., for the -750 mV relative to a CSE, instant off criterion, measured soil resistivity values were greater than 10,000 ohm-cm).

   When using the electrical resistance corrosion rate probes:

   a. The individual determining the installation of the probes and method of use will be qualified to NACE CP4, "Cathodic Protection Specialist" or similar

   b. The impact of significant site features and local soil conditions will be factored into placement of the probes and use of the data

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Buried and Underground Piping and Tanks* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In June 1994, leakage was identified in buried, carbon steel, emergency diesel generator (EDG) fuel oil lines. The leak was discovered through external visual inspection, internal boroscope inspection, and pressure drop air testing, and considered to be due to internal pitting corrosion. The 1½ inch schedule 80 carbon steel piping system was replaced with 2½ inch schedule 160 carbon steel lines in 1995. Excavation, fill placement, compaction, and testing of the soil were done in accordance with design specifications. The bedding material for the fuel oil lines is a select granular fill consisting of clean well graded sand. The coating material provided is a synthetic elastomeric tape wrap. A passive cathodic protection system was installed in 1995 to protect the buried fuel oil piping from corrosion. This passive system

became degraded as the sacrificial anodes were increasingly being drained off to station grounds.

In May 2015, an impressed current cathodic protection system was installed and placed in service to replace the passive cathodic protection system on the buried, carbon steel, EDG fuel oil lines. One of the two new rectifier units was in a degraded condition from August 2015 through February 2016, until it was restored to operation by corrective maintenance. The NACE annual inspection completed in April 2016 concluded that the system was providing adequate cathodic protection consistent with NACE criteria. Monthly inspections confirm rectifier operation.

2. In May 2004, portions of the Unit 2 auxiliary feedwater system experienced leakage in the buried carbon steel recirculation piping. The primary cause of the leak was pitting corrosion due to poorly applied coating. As a corrective action, the Unit 1 and Unit 2 AFW recirculation system piping is no longer buried and was rerouted through the safeguards building basement. The extent of condition assessment portion of the root cause evaluation noted the following:
   - The corresponding auxiliary feedwater recirculation line on Unit 1 had been discovered to be leaking and was subsequently bypassed and abandoned as part of a design change,
   - Stainless steel liquid waste piping in excellent condition,
   - Carbon steel chilled water piping with wrap intact and no indication of corrosion,
   - Carbon steel auxiliary feedwater piping with wrap in good condition and no indication of corrosion, and
   - Leaking fuel oil pipe with indications of localized pitting that was replaced and re-routed.
3. In June 2010, while removing coating from the Unit 2 condensate makeup buried carbon steel piping, pitting was identified on several areas of the pipe where the coating had been removed. The pitting was seen at three locations and was characterized as shallow. The as-found condition of the pipe was within code requirements and determined to be fit for service. Following inspection the coating was restored.
4. In July 2012, excavation revealed leakage from a buried Unit 2 ten inch stainless steel condensate supply line. There appeared to be an approximate three to four inch circumferential crack in the line that had started along the outside diameter of the pipe. The crack was determined to be caused by transgranular stress corrosion cracking due to mechanical damage by excavation equipment. The replacement pipe is not buried and has been rerouted through the turbine building.
5. In June 2016, a Dominion Energy fleet self-assessment was performed on the Underground Piping and Tank Integrity (UPTI) Program to ensure the program is supporting the goal of providing long term reliability of buried and underground piping and tanks; to ensure consistency with NEI 09-14, Guideline for the Management of Underground Piping and Tank

Integrity, and NSIAC requirements; and ensure the program meets industry best practices. Implementation of the UPTI Program was reviewed to confirm performance of inspections, effectiveness of scheduling and tracking, and program optimization based on inspection results.

This self-assessment identified one performance deficiency in that the 2015 UPTI Life Cycle Management Plan (LCMP) was issued by engineering transmittal without being approved at Plant Health Steering Committee. The 2016 UPTI LCMP was approved by Plant Health Steering Committee.

A strength was noted in that the inspections required by the UPTI LCMP are being scheduled, tracked, and performed as expected; and the results are being used appropriately to determine the next inspection. The UPTI team reviews operating experience during fleet calls and incorporates the experience into the program and inspections as appropriate.

6. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

7. In May 2017, during the as-found coating inspection on Unit 2 buried carbon steel condensate makeup piping, coating was missing on approximately 270 degrees of the pipe circumference from the center of the excavated area into the soil on the east side. Coating on the bottom was remaining. There was no visible leakage from this condensate makeup line piping segment. Ultrasonic testing of the piping segment demonstrated that the minimum wall thickness requirement was met or exceeded at each location tested. The protective coatings were restored.

8. In November 2017, as part of oversight review activities, the Buried Piping and Valve Inspection Activities (UFSAR Section 18.1.1) AMA owner confirmed that AMA inspections had

been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

9. In January 2018, an aging management program effectiveness review was performed of the initial license renewal Buried Piping and Valve Inspection Activities (UFSAR Section 18.1.1). Information from the summary of that effectiveness review is provided below:

   The Buried Piping and Valve Inspection Activities is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. Key activities of the Buried Piping and Valve Inspection Activities that were reviewed included the selection of components to be inspected, the inspection of components, the evaluation of inspection results, repairs/replacements, and AMA document updates. Engineering reports of inspections results from 2004 to 2016 were reviewed to confirm inspections were conducted at appropriate intervals and corrective actions taken consistent with the observed aging degradation. The review also included pertinent issues found in the Corrective Action Program from 2006 through 2017 for age related degradation of buried components within the scope of license renewal.

   A living Life Cycle Management Plan (LCMP) that identifies inspection plans at the next five year interval is maintained based on piping wall thickness calculations, risk ranking and internal/industry operating experience. In 2004, leakage from a buried auxiliary feedwater pipe and in 2012 leakage from a buried condensate pipe resulted in design changes to reroute the piping through non-buried environments. Observed coating degradations during recent inspections resulted in coating repairs and pipe wall thickness evaluations to anticipate rates of change and confirm fitness for service. Quarterly reviews by the fleet UPTI program owners review industry and plant operating experience, including corrective actions, to identify adjustments to the program. Recent fleet operating experience from North Anna Power Station for a service water to auxiliary feedwater pipe resulted in accelerated inspection schedules for similar carbon steel piping at SPS.

   In 2014, based on industry feedback, the EDG fuel oil sacrificial anode cathodic protection (CP) system was replaced with an impressed current system. Recent program reviews identified required updates to the maintenance procedures for the impressed CP system. In June 2017, as part of an Industry Material Review Visit, no adverse findings were noted for the UPTI program. Recent industry research and development is reviewed and incorporated into the program as appropriate. New soil survey studies consistent with EPRI 3002005294, "Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants," will identify any areas of soil corrosivity.

The above examples of operating experience provide objective evidence that the *Buried and Underground Piping and Tanks* program includes activities to perform volumetric and visual inspections to identify loss of material, cracking, and blistering for buried and underground piping and tanks within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Buried and Underground Piping and Tanks* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Buried and Underground Piping and Tanks* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Buried and Underground Piping and Tanks* program, following enhancement, will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.28 Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

Program Description

The *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program is an existing condition monitoring program that manages loss of coating integrity of the in-scope components exposed to closed-cycle cooling water, raw water, treated water, treated borated water, ~~and~~ waste water, and air-dry environments, that can lead to loss of base materials or downstream effects such as reduction in flow, reduction in pressure or reduction of heat transfer when coatings/linings degrade and become debris.

Periodic visual inspections are conducted for each coating/lining material and environment combinations of the internal surfaces of in-scope piping and components where loss of coating or lining integrity could impact the components or downstream component's intended function(s).

For tanks, ~~and~~ heat exchangers and piping, all accessible surfaces are inspected. ~~Piping inspections are sample based.~~ The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings are conducted in accordance with ASTM International Standards endorsed in RG 1.54, Revision 2, "Service Level I, II and III Protective Coatings Applied to Nuclear Power Plants," including guidance from the staff associated with a particular standard. For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces. Peeling and delamination is not acceptable. Blisters are evaluated by a coatings specialist. Blisters are limited to a few intact small blisters that are completely surrounded by sound material and with the size and frequency not increasing between inspections. Minor cracks in cementitious coatings are acceptable provided there is no evidence of debonding. Other degraded conditions are evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, the coating can be removed or physical testing is performed, where physically possible (i.e., sufficient room to conduct testing), in conjunction with repair or replacement of the coating/lining.

NUREG-2191 Consistency

The *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI.M42, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks.

Exception Summary

The following program element(s) are affected:

Detection of Aging Effects (Element 4).

1. Every four or six years, NUREG-2191 recommends either an inspection of a representative sample of 73 one foot axial length circumferential segments of piping or 50% of the total length of each coating/lining material and environment combination inspected, whichever is less at each unit. For two-unit sites, 55 one foot axial length sections of piping (nineteen if manufacturer recommendations and industry consensus documents were complied with during installation) are inspected per unit. An exception is taken to the inspection sample size, inspection, and re-inspection frequency.

Justification for Exception

For each unit, existing piping inspections are performed on 25% of the circulating water system (large bore piping) and service water system internal coatings every eighteen months, thereby inspecting 100% of the circulating water system and service water system piping every six years.

The existing coating on circulating water and service water piping approached the end of its expected service life and has been marginally successful in protecting the steel pipe from the corrosive effects of the brackish cooling water system. The coating has experienced localized failures exposing the pipe wall to brackish water resulting in corrosion of the exposed pipe material. The circulating water and service water piping is being repaired using a carbon fiber reinforced polymer (CFRP) lining to restore the piping pressure boundary and provide a corrosion-resistant barrier on piping internal surfaces. The CFRP relining is expected to be complete in future refueling outages.

For piping with CFRP lining, the inspection interval will be extended to twelve years if:

a. Identical coating/lining material is installed with the same installation requirements in redundant trains with the same operating conditions and at least one of the trains is inspected every six years, and
b. The coating/lining is not in a location subject to erosion that could result in damage to the coating/lining.

The determination to extend the inspection interval will be based on operating experience and inspection results.

2. If a baseline inspection has not been previously established, NUREG-2191 recommends a baseline coating/lining inspection occur in the 10-year period prior to the subsequent period of extended operation. Subsequent inspections are based on an evaluation of the effect of a coating/lining failure on the in-scope component's intended function, potential problems

identified during prior inspections, and known service life history. An exception is taken to performance of baseline inspections during each inspection interval.

Justification for Exception

Baseline inspections are not required because 100 percent of all accessible internal surfaces are inspected.

3. NUREG-2191 indicates that periodic visual examinations of a sample of piping internally lined with concrete be performed to verify degradation leading to loss of material or downstream effects such as reduction in flow and pressure. Opportunistic inspections of concrete lined fire protection system main loop piping will be performed. An exception is taken to perform periodic inspections.

Justification for Exception

Concrete lined cast iron fire protection system main loop piping is buried. Inspection of this piping is highly intrusive and would require excavation and implementation of a complex temporary modification to maintain a functional fire protection header. Management of the effects of aging for the fire protection system is described in AMP XI.M27, "Fire Water System." In accordance with the Fire Water System program (B2.1.16), the following tests and inspections will be performed:

- Fire protection system underground loop and main header flow test will be conducted at least once every five years. During the flow test, system hydraulic characteristics will be measured and evaluated for indication of internal piping degradation or flow obstructions. The flow test will measure system hydraulic resistance as a means of evaluating the internal piping conditions. Monitoring system piping flow characteristics ensures that signs of internal piping degradation from significant corrosion, sediment buildup or fouling will be detected in a timely manner.
- Underground supply piping is flushed through each of the outdoor fire hydrants annually. Full flow of clean, clear water is confirmed during flushing of annual hydrant flushes.
- Wet pipe sprinkler main drain flow tests and inspector test flushes will be performed to assure adequate water supply and proper system performance. Main drain testing will be performed for wet pipe sprinkler systems with alarm control valves to monitor and trend system pressure during flow conditions and identify degraded water supply conditions should they occur.
- The motor and diesel driven fire pumps are flow tested at least every 5 years to assure flow and pressure requirements are met.

Together, these tests provide reasonable assurance that flow blockage would be detected just as effectively as if internal inspections were being periodically conducted on a portion of the piping in consistent with NUREG-2191, AMP XI.M42, Table XI.M42-1. In addition, the fire water system is maintained at required operating pressure. Daily monitoring of the head and pressure in the hydro-pneumatic tank is performed. Alarm circuits monitor the system pressure, and low pressure is annunciated in the main control room via the motor driven and diesel driven fire pump start logic. A loss or decrease in system pressure would be noted and corrective actions initiated. This continuous monitoring is an effective means to detect potential through-wall flaws in the piping and piping components.

In August 2014, while conducting a fire hose station valve test, an underground fire main leak was suspected to have occurred. The suspected leak location was excavated and a circumferential break was noted in the pipe. The failed section of pipe was removed from the flanged end and submitted to the corporate materials lab for examination. Overall, the pipe section appeared to be in good condition. Visually, the pipe wall was sound, showing no signs of any extensive corrosion from the outside. Along the inner diameter, the cement lining had fractured away in the areas where the pipe was cut but the underlying metal was in excellent condition. In those areas outside the cuts, near the flange where the lining was still in place, cement lining was in good condition. The examination concluded that it is possible that a fabrication defect was present in this pipe. Away from the fracture, the overall condition of the pipe was good. No signs of any significant corrosion were seen along the outside or inside of the pipe. The heaviest corrosion noted in the form of pitting was along the outside of the pipe near the leak location.

The NRC approved a NUREG-2191 exception based on very similar justification as documented in the Safety Evaluation Report Related to the License Renewal of Fermi 2, Docket No. 50-341, dated July 2016 (ADAMS Accession No. ML16190A241).

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Scope of the Program (Element 1) and Detection of Aging Effects (Element 4)

1. Procedures will be revised to require additional inspections (100 percent of accessible coatings/linings) of the following tanks, piping, and miscellaneous components within the scope of subsequent license renewal and inspection frequencies will be modified, as necessary, to ensure consistency with NUREG-2191:
   - Circulating water system waterbox air separating tanks
   - Condensate polishing outlet piping (short segment; entire length is inspected)
   - Vacuum priming tanks
   - Vacuum priming seal water separator tanks
   - Auxiliary steam drain receiver tank
   - Water treatment piping (short segment; entire length is inspected)

- Flash evaporator demineralizer isolation valve
- Brominator mixing tank
- Pressurizer relief tanks

Parameters Monitored/Inspected (Element 3)

2. Programs will be revised to consistently reference coating aging mechanisms and add definitions for rusting, wear/erosion, and physical damage.

3. Procedures will be revised to require alignment of the internal coating/lining inspection criteria with the inspection criteria and aging mechanisms specified in the Coatings Condition Assessment Program.

4. Procedures will be revised to require inspections of cementitious coatings/linings and include aging mechanisms associated with cementitious coatings/linings described as cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation.

Detection of Aging Effects (Element 4)

5. Procedures will be revised to require cementitious coatings/linings inspectors to 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.

6. Procedures will be revised to require opportunistic inspections of piping internally lined with concrete and include aging associated with cementitious coatings/linings described as cracking due to chemical reaction, weathering, settlement, or corrosion of reinforcement; loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation.

Monitoring and Trending (Element 5)

7. Procedures will be revised to require a pre-inspection review of the previous "two" condition assessment reports, when available, be performed, to review the results of inspections and any subsequent repair activities.

8. Procedures will be revised to require inspection results be evaluated against acceptance criteria to confirm that the components' intended functions will be maintained throughout the subsequent period of extended operation based on the projected rate and extent of degradation. Where practical, (e.g., wall thickness measurements, blister size and (frequency), degradation will be projected until the next scheduled inspection.

Acceptance Criteria (Element 6)

9. Procedures will be revised to:

a. Specify there are no indications of peeling or delamination.

b. Require inspection of cementitious coatings/linings. Minor cracking and spalling is acceptable provided there is no evidence that the coating/lining is debonding from the base material.

c. Require, as applicable wall thickness measurements, projected to the next inspection, meet design minimum wall requirements.

Corrective Action (Element 7)

10. Procedures will be revised to permit the "removal" of coatings/linings that do not meet acceptance criteria, with the required evaluation and documentation.

11. Procedures will be revised to include as an alternative to repair, rework, or removal, internal coatings/linings exhibiting indications of peeling and delamination. The component may be returned to service if:

   a. Physical testing is conducted to ensure that the remaining coating is tightly bonded to the base metal,

   b. ~~The~~ the potential for further degradation of the coating is minimized, (i.e., any loose coating is removed, the edge of the remaining coating is feathered), ~~adhesion testing (e.g., pull-off testing, knife adhesion testing) is conducted at a minimum of three sample points adjacent to the defective area~~

   c. adhesion testing using ASTM International Standards endorsed in RG 1.54 (e.g., pull-off testing, knife adhesion testing) is conducted at a minimum of 3 sample points adjacent to the defective area,

   d. ~~An~~ an evaluation is conducted of the potential impact on the system, including degraded performance of downstream components due to flow blockage and loss of material or cracking of the coated component, and

   e. ~~Follow-up~~ follow-up visual inspections of the degraded coating are conducted within two years from detection of the degraded condition, with a re-inspection within an additional two years, or until the degraded coating is repaired or replaced.

12. Procedures will be revised to require when a blister does not meet acceptance criteria, and it is not repaired, physical testing is conducted to ensure that the blister is completely surrounded by sound coating/lining bonded to the surface. Physical testing consists of adhesion testing using ASTM International standards endorsed in RG 1.54. Where adhesion testing is not possible due to physical constraints, another means of determining that the remaining coating/lining is tightly bonded to the base metal is conducted such as lightly tapping the coating/lining. Acceptance of a blister to remain inservice should be based both on the potential effects of flow blockage and degradation of the base material beneath the

blister.~~additional inspections if one of the license renewal inspections does not meet acceptance criteria due to current or projected degradation.~~

13. Procedures will be revised to require additional inspections be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation (i.e., trending) unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. The number of increased inspections will be determined in accordance with the Corrective Action Program. However, there are no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. When inspections are based on the percentage of piping length, an additional 5% of the total length will be inspected. The timing of the additional inspections will be based on the severity of the degradation identified and will be commensurate with the potential for loss of intended function. However, in all cases, the additional inspections will be completed within the interval in which the original inspection was conducted, or if identified in the latter half of the current inspection interval, within the next refueling outage interval. These additional inspections conducted in the next inspection interval cannot also be credited towards the number of inspections in the latter interval. If subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections. Additional samples will be inspected for any recurring degradation to provide reasonable assurance that corrective actions appropriately address the associated causes. The additional inspections will include inspections with the same material, environment, and aging effect combination at both Unit 1 and Unit 2.
14. Physical testing is performed where physically possible (i.e., sufficient room to conduct testing) or examination is conducted to ensure that the extent of repaired or replaced coatings/linings encompasses sound coating/lining material.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In December 2008, the interior surface of the Unit 1 ECST was inspected in the filled condition. There was little evidence of corrosion, but there was minor blistering of the coating on the tank floor. The inspection of the Unit 1 ECST showed minor blistering and little evidence of corrosion that would impact minimum wall thickness.

2. In December 2008, the interior surface of the Unit 2 ECST was inspected in the filled condition. There was little evidence of corrosion, but there was minor blistering of the coating on the tank floors. An internal inspection of the Unit 2 ECST was performed in May 2017. Small blistering and pinhole damage was identified in areas of the coating along the tank walls. Internal coating repairs are scheduled in work management.

3. In December 2008, an engineering inspection of the 'A' main control room chiller revealed condenser tube erosion, but no leaks were identified and Engineering had no operability concerns. Per Engineering recommendation, Plastocor coating was placed on the tubes of 'A' main control room chiller in June 2009, and on the tubes of 'C' main control room chiller in July 2010. In January 2010, inspection revealed that the coating on the 'C' main control room chiller condenser outlet tubes had started to degrade. Coating in the tubes started to flake, crack and bubble up. Inspections of the tubes with a borescope revealed that there were spots where the copper oxide layer was flaking off. There was no corrosion, pitting, or cracking in the tubes or tubesheet. Maintenance successfully removed the loose, flaking and cracking coating. Engineering performed Eddy Current Inspection of the condenser tubes and no tube degradation was identified. In June 2010 the condenser outlet tubes were re-coated. Subsequent inspection in January 2011 revealed that the tubes and tubesheet were free of cracking, separation, or delamination. Coating was flaking three to three and half inches inside the tubes. Coating was removed where it was flaking. Inspection in June 2011 revealed no signs of degradation, pitting or erosion. Inspection performed in January 2015 and February 2016 found the condenser tubes to be acceptable for service.

4. During the Fall 2010 refueling outage (RFO), Engineering inspected the outlet line from a Unit 1 recirculation spray cooler. The line was found to have general corrosion occurring beneath the coating at the outlet flange interface on the upper endbell of the heat exchanger. The degraded coating was removed; base metal/weld repairs and coating repairs were performed during the Unit 1 fall RFO. Ultrasonic testing examination on the outlet service water flange was performed in November 2010. Exfoliation had not extended past the raised edge of the slip-on flange. Service water piping wall loss was not evident. Follow-up inspection of the outlet line was performed and coating degradation was found at the outlet flange interface on the upper end bell of the heat exchanger. Coating and weld repair were completed in November 2010. Another follow-up inspection in January 2011 noted areas of coating delamination, including the first four to six inches of pipe downstream from a service water motor operated valve, the area around the tap for a service water flow element and the tap for a service water resistance temperature detector. The areas of pipe where the delamination of coatings occurred were blasted and recoated in January 2011. Inspection of the recirculation spray cooler and ultrasonic testing of the service water vent piping is scheduled in work management.

5. In October 2010, five through wall holes were identified in a piping elbow of the Unit 1 "B" main condenser circulating water discharge piping. The piping contained raw water, and the material of construction was epoxy-coated carbon steel. Repairs were performed on the holes, and epoxy coating reapplied in February 2011.Subsequent inspections and repairs were performed in September 2016 with epoxy coating and March 2018 with the installation of the CFRP lining.

6. In November 2010, while removing a Unit 1 service water motor operated valve from the system to replace the an adjacent service water expansion joint, it was noted that the coating on the inner diameter of the pipe flange was not intact and the weld metal in the pipe to flange connection had corroded. The service water was in direct contact with the carbon steel pipe. Base metal/weld repairs and coating repairs were performed in November 2010. The weld repairs were visually inspected for a minimum acceptable wall thickness. The visual inspections were completed satisfactorily.

7. In November 2012, during the weld inspection of a Unit 2 main condenser outlet waterbox, eight areas for repair were identified due to degradation of the epoxy coating, including two through-wall areas. The waterbox contains raw water, and the material of construction is epoxy-coated carbon steel. Repairs were performed on the holes, and epoxy coating reapplied in November 2012. This is an example of recurring internal corrosion in the circulating water system. Subsequent inspections and repairs were performed in April 2014, October 2015, and April 2017.

8. In September 2014, a materials analysis was performed on buried cement lined grey cast iron fire main piping that was fractured during flow testing of hose station valves. The fracture was attributed to a latent material defect in the cast iron. The piping was removed and replaced with an equivalent spool piece. Based on the oxidation along the top segment of the crack, the pipe had been cracked for a long period of time. High levels of calcium deposits on the fracture (from the cement lining) indicate that the pipe was partially cracked at the top segment before factory installation of the cement liner (manufacturing process). Material analysis of the pipe determined that the microstructure consisted of graphite flakes that were approximately 75% ferrite and 25% pearlite. This resulted in a reduction in the supplied material hardness. Failure of pipe was not preventable through maintenance. The failure was caused by ground settling. During the pipe replacement it was observed that there was vertical misalignment between the replacement pipe and the existing buried pipe, which indicated that the buried side piping was exerting a large bending load at the anchor/foundation. This bending load along with the pre-existing crack and lower hardness value caused the pipe fracture. The balance of the failed pipe was found in good condition with no significant loss of cement lining material, corrosion, cracking, fouling, or reduction of pipe interior diameter.

9. In April 2015, circulating and service water Carbon Fiber Reinforced Polymer (CFRP) pipe repair was performed on the interior surface of circulating water and discharge service water piping to repair and strengthen the existing pipe systems. The service water and circulating water systems piping are constructed of carbon steel piping that was originally internally coated with a coal tar epoxy coating. Over the years of operation, the coating has experienced localized failures exposing the pipe wall to brackish water and resulting in corrosion of the exposed pipe material. Since 1990 there has been a long-term service water pipe repair project which replaced the coal tar coating with a coating system using a multi-functional epoxy coating product to improve the corrosion protection. This project was completed in July 1998. The new coating system did improve the corrosion protection; however, it still has a limited service life approximately 15 to 25 years which results in localized coating failures. This coating approached the end of its expected service life and has been only marginally successful in protecting the steel pipe from the corrosive effects of the brackish cooling water system.

   A permanent repair of the service and circulating water systems piping that restores the system pressure boundaries and provides a corrosion resistant barrier to the existing system was applied to sections of the service water and circulating water piping system. This design change addresses service water piping downstream of the component cooling heat exchangers and circulating water piping downstream of the Unit 1 condenser outlet valves. The CFRP system is used to repair any degraded piping sections. The CFRP relining began in 2015 and is expected to be complete in future refueling outages. The repair process used CFRP composite designed to take the place of the existing carbon steel pipe, and as such, becomes a pipe that is capable of meeting the original design requirements of this pipeline formed within the discharge piping. The outlet piping from the component cooling heat exchangers (CCHXs) that has been relined with CFRP is rated for full system pressure, design temperature, transient load, weight effects, and vacuum pressures combined with external ground water static pressure.

   In a relief request dated December 20, 2017 the NRC staff concluded that the proposed CFRP composite system provides reasonable assurance of the buried circulating water and service water piping structural integrity and leak tightness. The NRC staff stated in correspondence to Dominion dated December 20, 2017, "The CFRP repair system alternative will remain in place for the life of the plant." The station will continue to inspect approximately 25% of the circulating water system (large bore piping) and service water system internal coatings, including repaired sections, every 18 months, thereby inspecting 100% of the circulating water system and service water system piping every six years at each unit. The NRC further concluded, that based on operating experience, there is reasonable assurance to expect the CFRP repaired pipes to perform successfully and the maintenance and inspection programs will confirm acceptable performance during future inspection intervals. CFRP relining is expected to be complete in future refueling outages.

CFRP systems have been utilized in brackish water environments for over 25 years, and it is a common environment for application. This includes exposure to harsh freeze-thaw environments in bridge and pile applications within the transportation industry, upgrade to concrete infrastructure within power generation and industrial facilities, and pipeline repair and upgrade with CFRP - these types of applications are and have been completed in brackish environments with successful performance of the CFRP system.

10. In February 2016, engineering performed a coating/welding inspection inside the Unit 1 'B' component cooling heat exchanger inlet and outlet endbells. The inspection revealed fifteen areas inside the inlet endbell and ten areas on the outlet endbell requiring coating repairs. The outlet endbell also had three areas requiring base/metal weld repairs. There were no through-wall holes discovered. The weld repairs and coating were performed in February 2016. A quality inspector visually inspected the final repaired areas and a magnetic particle examination was performed on the final weld repairs. The work was completed and inspected satisfactorily.

Recurring Internal Corrosion (RIC)

Recurring internal corrosion, including through-wall failures due to pitting and general corrosion, has occurred in the coated/lined service water system piping, plumbing system piping, main condenser waterboxes and the 96-inch circulating water discharge piping. Corrective actions such as circulating water and service water liner installation that was started in April 2015 are in progress, and additional actions are scheduled to minimize the likelihood of piping and component degradation due to pitting and general corrosion in systems monitored by the *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28). Periodic system walkdowns in accordance with plant procedure will monitor for leakage. Additional corrective actions will be determined by the Corrective Action Program if significant loss of material is detected. Work orders have been created to replace affected portions of the plumbing system piping. Future occurrences of RIC will be documented in accordance with the Corrective Action Program. Corrective actions include:

a. Prior to the subsequent period of extended operation, the 96-inch circulating water outlet piping will be lined with CFRP. The design changes for both units are in progress, and no documented aging effects for CFRP coated sections of the 96-inch circulating water outlet piping have been identified. The CFRP design changes will be completed over the next several refueling outages. Separate design changes will install CFRP in the 96 inch circulating water inlet piping and the 24-, 30-, 36-, 42-, and 48-inch service water piping from the circulating water system to the recirculation spray and supply for the component cooling heat exchangers. For epoxy coated piping sections and main condenser channel heads that do not yet have the CFRP lining installed, inspection is performed of approximately 25% of the circulating water and service water system internal coatings each refueling cycle, thereby 100% of the circulating water and service water piping is inspected every six years. Since the initial installation of the CFRP system in April 2015, there have been no condition reports to date indicating a loss of coating integrity in CFRP lined components. The CFRP system has a 50-year service life.

The component cooling heat exchanger channel heads are epoxy-coated carbon steel exposed to raw water (service water). Inspections are performed yearly, which allows early detection of degradation of coatings and underlying metal. Inspection of the component cooling heat exchangers (CCHXs) in January 2011 discovered coating failures. Coating repairs were performed. A multi-functional epoxy coating system was applied to the Unit 1 CCHXs starting Unit 1 RFO 2013.

b. The CFRP lining is designed to meet the existing design requirements for the lines in which it will be installed and will serve as the system pressure boundary. In contrast to the existing carbon steel pipe, CFRP is not susceptible to pitting in a raw water environment. Therefore, augmented inspections will not be necessary on piping lined with CFRP. For piping sections and heat exchanger channel heads that do not yet have the CFRP lining installed, inspection of approximately 25% of the circulating water and service water system internal coatings each refueling cycle will be performed. As a result of the inspection protocol with a 25% sample population, 100% of the circulating water and service water internal coatings is inspected every six years.

Plant operating experience has demonstrated that the yearly inspections of the component cooling heat exchanger channel heads are frequent enough to detect degradation before causing a loss of intended function.

The above examples of operating experience provide objective evidence that the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program includes activities to perform visual inspections of internal surfaces to identify deficient or degraded coatings/linings for piping, piping components, heat exchangers and tanks within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program, following enhancement, will effectively manage aging prior to loss of intended function.

Conclusion

The continued implementation of the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program, following enhancement, will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.29 ASME Section XI, Subsection IWE

Program Description

The *ASME Section XI, Subsection IWE* program is an existing condition monitoring program that manages cracking, loss of material, loss of sealing, loss of preload, and loss of leak tightness by providing aging management of the steel liner of the concrete Containment. ASME Code, Section XI, Subsection IWE inspections are performed in order to identify and manage Containment liner aging effects that could result in loss of intended function for the subsequent period of extended operation. Included in this inspection program are the Containment liner plate and its integral attachments, Containment penetrations, Containment hatches, airlocks, and pressure retaining bolting.

Surface and volumetric examinations are performed to identify indications of degradation. The primary inspection method is visual examination (general visual, VT-1, VT-3) of surfaces for evidence of cracking, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents, and other signs of surface irregularities, including discernible liner plate bulges. Limited volumetric examinations (ultrasonic thickness measurement) and surface examinations (e.g., liquid penetrant) are performed, as required. Plant operating experience has not identified any discernible bulges requiring further examination. Acceptance criteria, corrective actions, and expansion of the inspection scope when degradation exceeding the acceptance criteria is found are in accordance with ASME Code, Section XI, Subsection IWE, Article IWE 3000.

For the third containment inspection interval, beginning during the third quarter of 2017, IWE Containment inservice inspections are performed in accordance with the 2007 Edition of ASME Code, Section XI, Subsection IWE (through the 2008 addenda), supplemented with the applicable requirements of 10 CFR50.55a(b)(2)(ix). Prior to the end of each interval, the IWE Program Plan is revised to reflect the appropriate update of ASME Code, Section XI, consistent with the provisions of 10 CFR 50.55a.

Containment seals and gaskets are included in the scope of the *10 CFR Part 50, Appendix J* program (B2.1.32). Service Level 1 coatings are included in the scope of the *Protective Coating Monitoring and Maintenance* program (B2.1.36).

The design of the Containment liner leak chase system does not include access boxes of the type addressed in NRC Information Notice 2014-07, and the liner-to-concrete interface does not include a moisture barrier. Therefore, the IWE program does not include any moisture barrier component.

Procedures will 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," will be used.

There are no stainless steel penetration bellows installed as part of the Containment pressure boundary. Stainless steel high energy pipes that penetrate the containment are connected to carbon steel penetration sleeves with dissimilar metal welds. Plant operating experience has not identified any stress corrosion cracking associated with these welds. The *ASME Section XI, Subsection IWE* program (B2.1.29) and the *10 CFR Part 50, Appendix J* program (B2.1.32) manage the aging of these dissimilar metal welds. Containment penetrations were not analyzed for cyclic fatigue and will require surface examinations in addition to visual examinations to detect cracking in stainless steel and dissimilar metal welds of penetration sleeves and components that are subject to cyclic loading. A one-time volumetric examination of metal liner surfaces that are inaccessible from one side will be performed if triggered by plant-specific operating experience. Sampling locations will be those susceptible to loss of thickness due to corrosion of the Containment liner that is inaccessible from one side.

The *ASME Section XI, Subsection IWE* program (B2.1.29) manages aging of the steel liner of the concrete containment building. The *10 CFR Part 50, Appendix J* program (B2.1.32) manages loss of leak tightness, loss of sealing, and leakage through containment. An evaluation of the acceptability of the inaccessible areas is completed whenever conditions are detected in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. A review of plant-specific operating experience associated with inaccessible areas from the IWE program has not identified any indications of corrosion.

NUREG-2191 Consistency

The *ASME Section XI, Subsection IWE* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI.S1, ASME Section XI, Subsection IWE.

Exception Summary

~~None~~ The following program elements are affected:

Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4)

1. NUREG-2191, Section X1.S1, ASME Section XI, Subsection IWE, recommends that steel, stainless steel, and dissimilar metal weld pressure-retaining components that are subject to cyclic loading, but have no CLB fatigue analysis, be monitored for cracking and supplemented with surface examination (or other applicable technique) in addition to visual examination. With the exception of high temperature components (e.g., high temperature penetrations), carbon steel components that are subject to cyclic loading (with no CLB fatigue analysis) are not monitored for cracking utilizing supplemental surface examinations.

Justification for Exception

The Containment contains dissimilar metal welds and steel components that are subject to cyclic loading but have no current licensing basis fatigue analysis. The Containment was designed in accordance with ASME Section III, Subsection N-415.1, 1968 edition. The six conditions in ASME Section III, Subsection N-415.1 were analyzed for the original design, initial license renewal, and subsequent license renewal to determine the need for a detailed fatigue analysis. Results of each analysis determined that a detailed fatigue analysis was not required for the containment liner due to stress fluctuations caused by temperature, pressure, and design earthquake cycles since all six conditions were shown to be satisfied.

The criteria used to evaluate cyclic fatigue included: 1) atmospheric to operating pressure cycle, 2) normal operation pressure fluctuation, 3) temperature difference – normal operation, startup and shutdown, 4) temperature difference change – normal operation, 5) temperature difference – dissimilar metals, and 6) mechanical loads. The containment liner fatigue analysis in Section 4.6 concluded that components that could be subject to cyclic loading, but have no current licensing basis fatigue analysis, are subjected to an acceptable and negligible amount of fatigue. Therefore, surface examinations will not be performed except for high temperature components that are subject to cyclic loading. UFSAR Section 14B.2.2.1 defines high-energy lines as those with a maximum operating temperature equal or exceeding 200°F. UFSAR Table 14B-2 provides a listing of the high-energy lines, their maximum operating temperatures, and their locations. The high temperature penetrations for the lines identified in Table 14B-2 that are located in Containment will be monitored for cracking with supplemental surface examinations (or other applicable technique) in addition to visual examination.

The *ASME Section XI, Subsection IWE* program will be enhanced to perform surface examinations in addition to visual examinations on accessible portions of high temperature mechanical penetrations to detect cracking for high temperature penetrations that could be subject to cyclic loading but have no CLB fatigue analysis.

Integrated leak rate testing (ILRT) and local leak rate testing (LLRT) is conducted for pressure boundary components per the *10 CFR Part 50, Appendix J* program (B2.1.32). The Type A ILRT would detect through-wall cracking. Additionally, VT-3 examinations are performed on accessible portions of the high temperature containment penetrations in accordance with the *ASME Section XI, Subsection IWE* program (B2.1.29). Operating experience has not identified failure of pressure retaining components (which have no CLB fatigue analysis) that are subject to cyclic loading. A review of license renewal applications with similar containment designs using later code years indicates fatigue waivers have been credited. Therefore, the existing *10 CFR Part 50, Appendix J* program (B2.1.32) and the *ASME Section XI, Subsection IWE* program (B2.1.29), following enhancement, are adequate to detect cracking without supplemental surface examination of carbon steel containment components subject to low levels of fatigue.

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Preventive Actions (Element 2)

1. Procedures will be revised to specify that whenever replacement of bolting is required, bolting material, installation torque or tension, and use of lubricants and sealants are in accordance with the guidelines of EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants," EPRI TR-104213, "Bolted Joint Maintenance & Application Guide," and the additional recommendations of NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation of Failure in Nuclear Power Plants."
2. Procedures will be revised to specify that for structural bolting consisting of ASTM A325, ASTM F1852, and/or ASTM A490 bolts, the preventive actions for storage, lubricants, and stress corrosion cracking potential discussed in Section 2 of RCSC (Research Council for Structural Connections) publication "Specification for Structural Joints Using ASTM A325 or A490 Bolts," will be used.

Parameters Monitored/Inspected (Element 3), Detection of Aging Effects (Element 4), Acceptance Criteria (Element 6)

~~3.~~ ~~Procedures will be revised to specify surface examination and acceptance criteria, in addition to visual examination, to detect cracking in stainless steel and dissimilar metal welds of penetration sleeves and components that are subject to cyclic loading but have no current licensing basis (CLB) fatigue analysis.~~ Procedures will be revised to augment visual examinations with surface examinations to manage cracking in the containment pressure retaining portions of the fuel transfer tube, fuel transfer tube enclosure, fuel transfer tube blind flange, dissimilar metal weld penetrations, and high-temperature steel piping penetrations. Surface examinations will be performed once during each ten year interval.

Detection of Aging Effects (Element 4)

4. Procedures will be revised to specify a one-time volumetric examination of metal liner surfaces that are inaccessible from one side if triggered by plant-specific operating experience. ~~Sampling locations will be those susceptible to loss of thickness due to corrosion of the Containment liner that is inaccessible from one side.~~The trigger for this supplemental examination is plant-specific occurrence or recurrence of measurable metal liner corrosion (base metal material loss exceeding 10% of nominal plate thickness) initiated on the inaccessible side or areas, identified since the date of issuance of the initial renewed license. This supplemental volumetric examination consists of a sample of one-foot square locations that include both randomly-selected and focused areas most likely to experience degradation based on operating experience and/or other relevant considerations such as environment. Any identified degradation is addressed in accordance with the applicable provisions of the ASME Section XI, Subsection IWE program. The sample size, locations, and any needed scope expansion (based on findings) for this one-time set of volumetric examinations should be determined on a plant-specific basis to demonstrate statistically, with 95% confidence, that 95% of the accessible portion of the containment liner is not experiencing corrosion degradation with greater than 10% loss of nominal thickness.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *ASME Section XI, Subsection IWE* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In 1998 and 1999, IWE inspection results for Unit 1 and Unit 2, respectively, found no significant degradation down to level of the interface joint with the concrete floor. Several areas of concrete were excavated to check the condition of the steel liner below the interface joint. These excavations confirmed the absence of significant degradation for the liner. Wall thickness measurements showed that considerable margin remains with respect to minimum acceptable values.

2. In 2015, while conducting a detailed visual examination (VT-1) of the concrete-liner interface of the Unit 2 Containment, per the ASME Code, Section XI, Subsection IWE, Table IWE-2500-1, Category E-C, areas with degraded coatings and surface corrosion were identified in the concrete-liner interface along the back of the Containment sump. The VT-1 examination did not reveal any adverse condition other than surface corrosion in the area identified. Corrective action, in accordance with IWE-3122, resulted in cleaning the surface area, performing non-destructive examination (NDE), and recoating the surface. Ultrasonic testing (UT) verified wall thickness integrity. The lowest reading was 0.398 inches, with nominal wall thickness of 0.375 inches.

3. In 2015, follow-up inspection of the coatings repair to the Containment liner to floor interface identified two areas behind the inside recirculation spray pump suction header supports, which required further coatings repair. A work order was issued and the coatings in these two areas were repaired in May 2017.

4. In May 2016, the NRC issued Regulatory Issue Summary (RIS) 2016-07, "Containment Shell or Liner Moisture Barrier Inspection." An NRC inspection in December 2003, identified an issue of very low safety significance (Green) that was treated as a Non-Cited Violation. During examination of the interior surfaces of the containment metal liner, the inspectors identified several areas with degraded coatings and rust on the containment liner at the interface of the metal liner and the bottom interior concrete floor. The inspectors also identified that the moisture barrier at the interface between the metal liner plate and interior concrete floor was degraded.

   During the evaluation and corrective actions, it was determined that the design of the Containment did not include a moisture barrier at the interface in question, and the material that was acting as a moisture barrier was silicone caulk that had been applied during liner coatings repair. The caulk was applied only in areas where the concrete had separated from the steel liner and was not continuous around the perimeter of the Containment. Work requests were submitted to remove the caulk and repair the concrete to eliminate the gaps between the concrete and the steel liner.

   RIS 2016-07 noted the following:

   - The original SPS design did not include a moisture barrier at the interface between the concrete floor and the steel liner.
   - Subsequently, a moisture barrier was installed at this junction.
   - The moisture barrier was later removed.

   The RIS further stated that when the licensee reintroduced this configuration (no moisture barrier), an augmented examination (Examination Category E-C) should have been performed, or an evaluation should have been completed demonstrating why augmented examinations in accordance with ASME Code, Section XI, IWE-1241 were unnecessary.

   In July 2017, a plant Containment Inservice Inspection (CISI) Basis Document was issued, which included a Technical Position that demonstrated why augmented examinations in accordance with ASME Code, Section XI, IWE-1241 were unnecessary:

   As indicated in the CISI Basis Document, the Containment configuration includes a concrete containment with a steel liner and a concrete floor poured flush to the steel liner. The original design did not include a moisture barrier at the interface between the concrete floor and the steel liner. The concrete floor slab interface with the metal liner is included for examination and specifically identified as a separate item in the Units 1 & 2 CISI Program for IWE. The visual examination is performed each inspection period in accordance with the requirements of Examination Category E-A, for Item No.: E1.11, Accessible Surface Areas, which is exactly the same examination requirement as for Item No.: E1.30, Moisture Barriers. If surface areas are identified with indications of potential degradation and aging affects at this interface area, the affected surface areas will be evaluated. If the areas are determined to have accelerated degradation, then the subject areas will be included under Examination Category E-C, and examined accordingly. This examination evaluation method meets the examination requirements for the interface area at concrete to metal interfaces as described in NRC RIS 2016-07.

Currently, the Containment IWE ISI Plan identifies Examination Item No. E1.11A, "Accessible Surface Areas (Concrete Floor Slab to Metal Liner Interface)", to be examined each inspection period. For the first period (in the third interval), the floor slab to metal liner interface surface in Item No. E1.11A will receive an augmented visual examination (VT-1) in accordance with Examination Category E-C. If the examination is acceptable, the frequency will revert back to examination under Category E-A using the General Visual examination technique.

5. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

6. In November 2017, as part of oversight review activities, the ISI Program - Containment Inspection Activity (UFSAR Section 18.2.12) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

7. In January 2018, an aging management program effectiveness review was conducted for the ISI Program - Containment Inspection Activity (UFSAR Section 18.2.12), which included the *ASME Section XI, Subsection IWE* program. Information from the summary of that effectiveness review is provided below:

   The ISI Program - Containment Inspection Activity is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. The ISI

Program - Containment Inspection Activity implements the inspection, testing and examination requirements including references to documents that implement repair/replacement activities of ASME Section XI, as required and conditioned by Title 10 Code of Federal Regulations (CFR) Part 50, Section 55a Codes and standards (10 CFR 50.55a). In addition to the normal IWE inspections which are performed once a period, inspections of the liner are performed every outage in accordance with station procedures by the ISI Program - Containment Inspection Activity personnel and by the stations coating engineer. These inspections along with the normal IWE inspections ensure that the liner, which is the final fission product barrier, remains capable of performing its design function and that any noted conditions that could affect containment integrity are promptly resolved.

The above examples of operating experience provide objective evidence that the *ASME Section XI, Subsection IWE* program includes activities to perform visual examinations (general visual, VT-3, VT-1) and limited volumetric examinations (ultrasonic thickness measurement) to manage the aging effects of manages cracking, loss of material, loss of sealing, loss of preload, and loss of leak tightness for the Containment liner plate and its integral attachments within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *ASME Section XI, Subsection IWE* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *ASME Section XI, Subsection IWE* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *ASME Section XI, Subsection IWE* program, following enhancement, will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.31 ASME Section XI, Subsection IWF

Program Description

The *ASME Section XI, Subsection IWF* program is an existing condition monitoring program that manages loss of material, cracking, loss of preload, and loss of mechanical function for supports of Classes 1, 2, and 3 piping and components. There are no Class MC supports at SPS.

During the fifth inservice inspection interval (December 2013 to October 2023), inspections of supports for Class 1, 2, and 3 piping and components are performed consistent with the 2004 edition of ASME Code, Section XI, as approved in 10 CFR 50.55a. In conformance with 10 CFR 50.55a(g)(4)(ii), the inservice inspection program is updated during each successive 120 month inspection interval to comply with the requirements of the latest edition and addenda of the Code specified 12 months before the start of the inspection interval. ASME Code edition will be used consistent with the provisions of 10 CFR 50.55a during the subsequent period of extended operation.

Supports for Class 1, 2, and 3 piping and components are selected for examination per the requirements of ASME Code, Section XI, Subsection IWF. Acceptance standards are specified in ASME Code, Section XI, Subsection IWF, Article IWF 3400. The scope of the inspection for supports is based on class and total population as defined in Table IWF 2500-1. When a component support requires corrective measures in accordance with the provisions of Subsection IWF 3000, that support is reexamined during the next inspection period. When the reexaminations do not require additional corrective measures during the next inspection period, the inspection schedule reverts to the requirements of the original inspection program.

Component support examinations that detect flaws or relevant conditions exceeding the acceptance criteria of Subsection IWF 3400 are extended to include additional examinations in accordance with Subsection IWF 2430. The ASME Code, Section XI, Subsection IWF program provides a systematic method for periodic examination of supports for Class 1, 2, and 3 piping and components. The primary inspection method is visual examination. The instructions and acceptance criteria for the visual examinations (VT-3) are included in existing procedures.

If a component support does not exceed the acceptance standards of IWF-3400, but is electively repaired to as-new condition, then the sample is increased or modified to include another support that is representative of the remaining population of supports that were not repaired.

The requirements of subsection IWF are supplemented to include monitoring of high-strength bolting (actual measured yield strength greater than or equal to 150 kilo-pounds per square inch (ksi) or 1,034 megapascals (MPa) and greater than one inch nominal diameter), with volumetric examination comparable to that of ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 to detect cracking in addition to the VT-3 examination. In each 10-year period during the subsequent period of extended operation, a representative sample of bolts will be inspected. The sample will be 20% of the population (for a material/environment combination) up to a maximum of 25 bolts.

Procedures will 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," will be used.

This program includes a one-time inspection within five years prior to entering the subsequent period of extended operation of an additional 5% of the sample populations for Class 1, 2, and 3 piping supports. The additional supports will be selected from the remaining population of IWF piping supports and will include components that are most susceptible to age-related degradation.

NUREG-2191 Consistency

The *ASME Section XI, Subsection IWF* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.S3, ASME Section XI, Subsection IWF.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Scope of Program (Element 1)

1. Procedures will be enhanced to evaluate the acceptability of inaccessible areas (e.g., portions of supports encased in concrete, buried underground, or encapsulated by guard pipe) when conditions in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.

Preventive Actions (Element 2)

2. Procedures will be revised to specify that whenever replacement of bolting is required, bolting material, installation torque or tension, and use of lubricants and sealants will be in accordance with the guidelines of EPRI NP-5769, EPRI TR-104213, and the additional recommendations of NUREG-1339.

3. Procedures will be revised to specify that for structural bolting consisting of ASTM A325, ASTM F1852, and/or ASTM A490, the preventive actions for storage, lubricants, and stress corrosion cracking potential discussed in Section 2 of RCSC (Research Council for Structural Connections) publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts," will be used.

Parameters Monitored or Inspected (Element 3)

4. Procedures will be revised to specify that for NSSS component supports, Class 1 high strength bolting greater than one inch nominal diameter, including ASTM A325 and/or ASTM A490 bolts (including respective equivalent twist-off type ASTM F1852 and/or ASTM F2280 bolts), will be monitored for SCC.

Detection of Aging Effects (Element 4)

5. Procedures will be revised to specify a one-time inspection within five years prior to entering the subsequent period of extended operation of an additional 5% of the sample populations for Class 1, 2, and 3 piping supports. The additional supports will be selected from the remaining population of IWF piping supports and will include components that are most susceptible to age-related degradation.

6. Procedures will be revised to specify that, for NSSS component supports, high-strength bolting greater than one inch nominal diameter, volumetric examination comparable to that of ASME Code, Section XI, Table IWB-2500-1, Examination Category B-G-1 will be performed to detect cracking in addition to the VT-3 examination. In each 10-year period during the subsequent period of extended operation, a representative sample of bolts will be inspected. The sample will be 20% of the population (for a material / environment combination) up to a maximum of 25 bolts.

Monitoring and Trending (Element 5)

7. Procedures will be revised to specify that, if a component support does not exceed the acceptance standards of IWF-3400, but is electively repaired to as-new condition, then the sample is increased or modified to include another support that is representative of the remaining population of supports that were not repaired.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *ASME Section XI, Subsection IWF* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In August 2013, during an ASME Code inspection, corrosion was identified on the top horizontal 3 x 3 inch angle of a service water system pipe support in Unit 1. The gap listed for this area of the pipe support could not be determined. This was considered an ASME Code, Section XI rejectable indication. Engineering inspected the angle to quantify the material loss so that it could be evaluated. Engineering evaluation determined the mild surface rust observed is negligible. The hanger meets all its design basis requirements and remains fully functional and fully qualified in this as-found condition. This condition does not represent any loss of support function for this pipe support. The support drawing has been revised to include a note to reflect the minor material loss. The support was determined to be functional by evaluation; therefore, no scope expansion is required.
2. In May 2014, during an expanded scope examination determined consistent with Subsection IWF-2430, observed indications deemed not acceptable were found and documented with a support associated with a recirculation pump in Unit 2. Specifically, one nut was found not flush tight to the support plate and unable to be moved by hand. Two other studs were found to have been flame cut, one of which still has part of the nut still on the stud. The examination was an expanded scope examination due to missing bolts/nuts discovered during a previous examination in April 2014. The missing bolts/nuts were replaced and the inspection scope was expanded. Engineering evaluation of the condition identified in the expanded inspection determined the support was functional as-found and the loose nut was tightened.
3. In May 2014, during an NDE/ISI examination in the Unit 2 Pressurizer Relief Tank Room, the inner bolt on both sides of the pipe clamp were found not tight against the side of the clamp. With some pressure, the bolts could be moved side to side but could not be rotated in their holes. The pipe clamp could not be rotated on the pipe. This condition was document on the NDE report and was found to be rejectable. This support was examined as part of the ASME Code, Section XI NDE/ISI scope for the 2014 Unit 2 refueling outage. Engineering evaluation in accordance with Subsection IWF-3122 (acceptance by correction or acceptance by evaluation) determined the support was functional. The support was determined to be functional by evaluation; therefore, no scope expansion is required.
4. In December 2015, an effectiveness review of the In-service Inspection (ISI) Program - Components and Component Support Inspections Activity (UFSAR Section 18.2.11) was performed. The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. No gaps were identified by the effectiveness review.

5. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.
6. In November 2017, as part of oversight review activities, the In-service Inspection (ISI) Program - Components and Component Support Inspections Activity (UFSAR Section 18.2.11) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.
7. In January 2018, an aging management program effectiveness review was conducted for the In-Service Inspection (ISI) Program - Component and Component Support Inspections Activity (UFSAR Section 18.2.11), which includes the inspection of *ASME Section XI, Subsection IWF* program. Information from the summary of that effectiveness review is provided below:

   The In-Service Inspection (ISI) Program - Component and Component Support Inspections Activity is meeting or exceeding the requirements consistent with the selected elements of NEI 14-12, "Aging Management Program Effectiveness." Key activities of the AMA that were reviewed include the performance of (non-destructive examinations) NDE to meet the requirements of ASME Code, Section XI and AMA document updates. An ASME Section XI Program is required by the Code of Federal Regulations. A 10-year period (July 2006 to June 2016) of condition reports and engineering evaluations has been reviewed to identify programmatic issues. No programmatic issues were identified as a result of this review.

   ISI examinations are scheduled appropriately in the Unit 1 ISI Schedule (Unit 1, Inservice Inspection Schedule, Fifth Inspection Interval, December 14, 2013 to October 13, 2023) and the Unit 2 ISI Schedule (Unit 2, Inservice Inspection Schedule, Fifth Inspection Interval, May 10, 2014 to May 9, 2024) to meet the requirements of ASME Code, Section XI and the Code of Federal Regulations. The Period 1, Fifth Interval ISI examinations have been completed to meet the ASME Section XI Code requirements. The ISI plan and the ISI schedule are updated periodically to implement new code cases of benefit and new rules and regulations, as required. There have been no new issues revealing service induced degradation to date in the fifth Interval.

The above examples of operating experience provide objective evidence that the *ASME Section XI, Subsection IWF* program includes activities to perform visual examinations (VT-1, VT-3) and volumetric examinations to manage loss of material, cracking, loss of preload, and loss of mechanical function for supports of Classes 1, 2, and 3 piping and components, and to initiate corrective actions. Occurrences identified under the *ASME Section XI, Subsection IWF* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *ASME Section XI, Subsection IWF* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *ASME Section XI, Subsection IWF* program, following enhancement, will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.34 Structures Monitoring

Program Description

The *Structures Monitoring* program is an existing condition monitoring program that manages aging of the structures and components that are within the scope of subsequent license renewal by managing the following aging effects:

- Cracking
- Cracking and distortion
- Cracking, loss of material
- Cracking, loss of bond, and loss of material (spalling, scaling)
- Increase in porosity and permeability, cracking, loss of material (spalling, scaling)
- Loss of material
- Loss of material (spalling, scaling) and cracking
- Loss of material, change in material properties
- Loss of mechanical function
- Loss of preload
- Loss of sealing
- Reduction in concrete anchor capacity
- Reduction of foundation strength and cracking
- Reduction or loss of isolation function

The *Structures Monitoring* program implements the requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," consistent with guidance of U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," and Nuclear Management and Resources Council 93-01, "Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants". The scope of the *Structures Monitoring* program includes structures and components in the scope of subsequent license renewal. The program relies on periodic visual inspections to monitor and maintain the condition of structures and components within the scope of subsequent license renewal. Inspections are conducted by qualified personnel at a frequency not to exceed five years, except for wooden poles, which will be inspected on a 10-year frequency. The interval between successive recurring inspections may be decreased based on conditions discovered in previous inspections.

Structural monitoring inspections consist primarily of periodic visual examination of accessible structures and components performed by qualified personnel. For concrete and associated components, ACI-349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures," and other applicable industry documents are used as guidance for the inspections, inspector qualifications, and evaluation of inspection results. The inspection program for structural steel is similar to the concrete program and is based on the guidance provided in the AISC Specification for Structural Steel Buildings and Code of Standard Practice. For earthen structures, evaluation of inspection results is performed by a qualified civil/structural engineer.

Procedures will include preventive actions to provide reasonable assurance of structural bolting integrity, as discussed in Electric Power Research Institute (EPRI) documents (such as EPRI NP-5067, "Good Bolting Practices, A Reference Manual for Nuclear Power Plant Maintenance Personnel," and TR-104213, "Bolted Joint Maintenance & Application Guide"), American Society for Testing and Materials (ASTM) standards, and AISC specifications, as applicable.

In order to evaluate the potential of water to cause degradation of inaccessible below-grade concrete, samples of groundwater will be taken at intervals not to exceed five years. The water chemistry is evaluated, and should the results of water testing indicate potentially harmful levels of substances such as chlorides > 500 ppm, sulfates > 1,500 ppm, or a pH < 5.5, inaccessible areas are assessed for aging when aging degradation exists in accessible areas and opportunistically inspected when excavated.

Ground water monitoring has shown the ground water to be non-aggressive, except for one sampling point. In 2007, a sample with a significantly high chloride level was obtained from the Turbine Building sump. Subsequent sample results from this sump have found additional chloride levels above the acceptance limit. An inspection was performed to assess the structure for any degradation that could be attributed to the elevated levels of chloride. The inspection found no evidence of significant degradation. There have been no indications of concrete degradation due to elevated chloride levels anywhere in the plant. Engineering continues quarterly monitoring of the ground water in this sump.

For surfaces provided with protective coatings, observation of the condition of the coating is an effective method for identifying the absence of degradation of the underlying material. Therefore, coatings on structures within the scope of the *Structures Monitoring* program are inspected only as an indication of the condition of the underlying material.

ASME Code, Section XI visual examinations (VT-1) or surface examinations will be conducted to detect cracking of stainless steel and aluminum components exposed to aqueous solutions or air environments containing halides. A minimum sample of 25 inspections will be performed from each of the aluminum and stainless steel component populations every ten years.

If any sampling-based inspections to detect cracking in aluminum and stainless steel do not meet the acceptance criteria, additional inspections will be conducted, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (i.e., 10 year inspection interval) in which the original inspection was conducted. Where practical, the inspections will focus on the bounding or lead components most susceptible to aging because of time in-service, severity of operating conditions, and lowest design margin.

Concrete inspection results are evaluated to identify changes that could be indicative of Alkali-Silica Reaction (ASR) development. If indications of ASR development are identified, the evaluation considers the potential for ASR development in concrete that is within the scope of the *ASME Section XI, Subsection IWL* program (B2.1.30), the *Structures Monitoring* program (B2.1.34), or the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.35). In 1988, a research study was performed to evaluate the degradation processes that could affect the reinforced concrete structures. Concrete core samples were secured from the intake canal, Unit 1 Condensate Storage Tank Missile Shield, Unit 2 Safeguards Building and Unit 2 Containment. Based on testing of these samples, the study concluded that there was no evidence of ASR.

Evaluation of inspection results includes consideration of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.

Structural sealants, seismic gap joint filler, vibration isolation elements, and other elastomeric materials are monitored for cracking, loss of material, and hardening. These elastomeric elements are acceptable if the observed loss of material, cracking, and hardening will not result in a loss of intended function. Visual inspection of elastomeric elements is supplemented by tactile inspection to detect hardening if the intended function is suspect.

Procedures will 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," will be used.

Spent fuel pool (SFP) liner leakage through the leak chase channels is monitored. An alarm is provided on the SFP to sound at a level loss of approximately 0.5 feet (UFSAR Section 9.5.3.3). A review of recent leak chase channel monitoring reports shows acceptable leakage rates with no tell-tale drains being completely blocked.

The *Masonry Walls* program (B2.1.33) and the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.35) are implemented as part of this program.

NUREG-2191 Consistency

The *Structures Monitoring* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.S6, Structures Monitoring.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Scope of Program (Element 1)

1. Procedures will be revised to include inspection of the following structures that are within the scope of subsequent license renewal: decontamination building, radwaste facility, health physics yard office building, laundry facility, and machine shop. <u>Inspections for the added structures will be performed under the enhanced program in order to establish quantitative baseline inspection data prior to the subsequent period of extended operation.</u>

Preventive Actions (Element 2)

2. Procedures will be revised to include preventive actions to ensure bolting integrity for replacement and maintenance activities by specifying proper selection of bolting material and lubricants, and appropriate installation torque or tension to prevent or minimize loss of bolting preload and cracking of high-strength bolting. 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," will be used.
3. <u>The checklist for structural and support steel will be revised to indicate: "Are any connection members loose, missing or damaged (bolts, rivets, nuts, etc.)?".</u>

Detection of Aging Effects (Element 4)

4. ~~Procedures will be revised to require at least five years of experience (or ACI inspector certification) for concrete inspectors to be consistent with ACI 349.3R-002.~~ Procedures will be revised to eliminate options for inspector qualifications that are not consistent with ACI 349.3R-002.

~~5.~~ ~~Procedures will be revised to inspect wooden power poles on a 10-year frequency.~~ Procedures will be revised to specify that wooden pole inspections will be performed every ten years by an outside firm that provides wooden pole inspection services that are consistent with standard industry practice. Visual examinations may be augmented with soundings or other techniques appropriate for the type, condition, and treatment of the wooden poles, including borings to determine the location and extent of decay and excavation to determine the extent of decay at the groundline.

6. Procedures will be revised to specify that evaluation of inspection results includes consideration of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.

7. Procedures will be enhanced to specify VT-1 inspections to identify cracking on stainless steel and aluminum components. A minimum of 25 inspections will be performed every ten years during the subsequent period of extended operation from each of the stainless steel and aluminum component populations assigned to the Structures Monitoring program. If the component is measured in linear feet, at least one foot will be inspected to qualify as an inspection. For other components, at least 20% of the surface area will be inspected to qualify as an inspection. The selection of components for inspection will consider the severity of the environment. For example, components potentially exposed to halides and moisture would be inspected, since those environmental factors can facilitate stress corrosion cracking.

Corrective Actions (Element 7)

8. Procedures will be enhanced to specify for the sampling-based inspections to detect cracking in stainless steel and aluminum components, additional inspections will be conducted if one of the inspections does not meet acceptance criteria due to current or projected degradation, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement for all components constructed of the same material and exposed to the same environment. No fewer than five additional inspections for each inspection that did not meet acceptance criteria or 20 percent of each applicable material, environment, and aging effect combination will be inspected, whichever is less. Additional inspections will be completed within the 10-year inspection interval in which the original inspection was conducted. The responsible engineer will initiate condition reports to generate work orders to perform the additional inspections. The responsible engineer will evaluate the inspection results, and if the subsequent inspections do not meet acceptance criteria, an extent of

condition and extent of cause analysis will be conducted. The responsible engineer will then 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 of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. 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 Corrective Action Program.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Structures Monitoring* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In March 2007, a condition report (CR) was written to document a ground water monitoring sample with a chloride level of 1210 ppm, which exceeded the acceptance limit of <500 ppm. This sample was obtained from the Turbine Building sump. Corporate and site Engineering continue to monitor the quarterly sample results from the Turbine Building sump and have found additional chloride levels above the acceptance limit, as high as 2700 ppm. An inspection of the Turbine Building sump was performed in July 2008 to assess the sump structure for any degradation that could be attributed to the elevated level of chlorides. The inspection found no evidence of significant degradation to the interior concrete. There are no safety-related components in the vicinity of the Turbine Building sump, and there have been no indications of concrete degradation due to elevated chloride levels anywhere in the plant.

   The source of the chlorides has not been determined. The Turbine Building sump is the deepest dewatering point and closest to the Intake Canal where expected underground leakage from the canal could influence the chloride level. The potential for in-plant sources of chlorides reaching the sump via secondary drains or local ground water was studied and determined to be unlikely. An Engineering evaluation concluded that, while the chloride level has remained high in the Turbine Building sump, the other sumps/piezometer well locations, some of which are located in close proximity to the Turbine Building sump, have been found to be consistently within acceptable levels. Engineering will continue to monitor the chloride levels in the Turbine Building sump on a quarterly basis. The plant procedure has been revised to maintain sampling requirements so that trending may continue but eliminate the comparison to the acceptance criterion for this sampling point.

2. In May 2011, a spall was found on the inside concrete surface of the bioshield wall of the Unit 2 Containment 'C' steam generator cubicle. The spall was approximately six inches long by six inches wide and 1-1/4 inches deep. The reinforcing steel was not exposed. It was

determined that the bioshield wall remained fully functional, but the spalled concrete required repair prior to unit startup to prevent potential degradation of the reinforcing steel. A work order was submitted and the spalled concrete has been repaired.

3. In December 2011, several embedded anchor bolts for the condenser unit of a Unit 1 Control Room chiller were found to be degraded. The anchor bolts displayed signs of corrosion and material loss. A work order was submitted and the anchor bolts were repaired in December 2011, which consisted of chipping the existing concrete around the anchor bolts until sound metal was reached, performing a weld repair of each anchor bolt, and repairing the concrete slab.

4. In October 2012, leakage (approximately one gpm) was identified in the bottom portion of the steel to concrete joint (interface between the steel elbow and the concrete pipe) of the Unit 2 'D' 96-inch circulating water line. Corrosion and coating failure on the bottom third of the pipe was observed at this location. The urethane seal around the leading (upstream) edge of the joint was also missing and degraded. A work order was submitted and the Unit 2 'D' 96-inch circulating water line joint has been repaired.

5. In January 2013, the Service Building roof was leaking, causing water to collect in two locations on the floor of the Service Building hallway. The first location was near the #1 EDG room. The second location was approximately halfway between the doors to the health physics area and the door to the operations annex. A work order was submitted and degraded roof areas were repaired.

6. In December 2014, a CR was written to document a ground water monitoring sample that showed a chloride level of 610 ppm. The sampling point that exhibited unacceptable chloride levels is located adjacent to the Intake Canal, which draws water from the river. Three months later the same sampling point was found to have chlorides at 676 ppm. These values exceeded the acceptance limit of <500 ppm. The CR evaluation determined that the elevated chloride level was probably due to unusually low rain fall on the James River, temporarily increasing its natural salinity. Results from subsequent monitoring of ground water have been acceptable, and no degradation of concrete due to elevated chloride levels has been identified.

7. In December 2015, an effectiveness review of the Civil Engineering Structural Inspection Activity (UFSAR Section 18.2.6) was performed. The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. No gaps were identified by the effectiveness review.

8. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

- Procedures credited for license renewal were identified
- Procedures were consistent with the licensing basis and bases documents
- Procedures contained a reference to conduct an aging management review prior to revising
- Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

Procedure changes were completed as necessary to ensure the above items were satisfied.

9. In November 2017, as part of oversight review activities, the Civil Engineering Structural Inspection Activity (UFSAR Section 18.2.6) AMA owners confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments required in UFSAR Chapter 18. Security lighting poles were within the scope of license renewal but were not inspected during the Civil Engineering Structural Inspection Activity cycle completed in 2012. The omission of the security lighting poles from the 2012 inspection cycle was entered in the Corrective Action Program. In December 2017, Civil Engineering inspected the light poles and noted no degradation. The License Renewal Application and supporting documentation were reviewed for in-scope structures requiring inspection, and that information was cross-referenced with the implementing procedure to confirm aging management program commitments required by UFSAR Chapter 18 were satisfied. The security lighting poles are identified in the implementing procedure as being within scope of license renewal and will be inspected during subsequent structural inspections.

10. In January 2018, an aging management program effectiveness review was conducted for the Civil Engineering Structural Inspection Activity (UFSAR Section 18.2.6), which include the *Structures Monitoring* program (B2.1.34), *Masonry Walls* program (B2.1.33) and the *Inspection of Water-Control Structures Associated with Nuclear Power Plants* program (B2.1.35). Information from the summary of that effectiveness review is provided below:

    The Civil Engineering Structural Inspection Activity is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. Key activities of the AMA that were reviewed included structural inspections for aging management that have been incorporated into the periodic inspections performed for Maintenance Rule compliance. Maintenance Rule inspections, along with trending and evaluation for evidence of aging effects, ensure the continuing capability of civil engineering structures to meet their intended functions consistent with the current licensing basis. A 10-year review of inspection results and corrective actions did not identify any aging that resulted in a loss of intended function(s).

11. In March 2018, the existing Structures Monitoring program was revised to improve the inspection techniques and to adopt new inspection techniques to manage aging effects associated with ASR degradation of concrete structures and components consistent with industry operating experience IE Notice 2011-20 (IN 2011-20), "Concrete Degradation by Alkali-Silica Reaction," and EPRI Report #3002005389 (2015), "Tools for Early Detection of ASR in Concrete Structures."

The above examples of operating experience provide objective evidence that the *Structures Monitoring* program includes activities to perform volumetric and visual inspections to identify aging effects for structures, structural supports, and structural commodities within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Structures Monitoring* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Structures Monitoring* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Structures Monitoring* program, following enhancement, will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.36 Protective Coating Monitoring and Maintenance

Program Description

The *Protective Coating Monitoring and Maintenance* program is an existing mitigative and condition monitoring program that manages loss of coating integrity of Service Level I coatings inside Containment. ~~The program manages coating system selection, application, visual inspections, assessments, repairs, and maintenance of Service Level I protective coatings as defined in~~ The program maintains and monitors the aging of Service Level 1 coatings consistent with RG 1.54 Revision 2, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants".

Maintenance of coatings is consistent with ASTM D 5163-08, "Standard Guide for Establishing a Program for Condition Assessment of Coating Service Level I Coating Systems in Nuclear Power Plants." The program includes activities to monitor and assess the material condition of Service Level I coatings applied to steel and concrete surfaces inside Containment by performing visual inspections with qualified inspectors to ensure there is no coating degradation.

Maintenance of Service Level I coatings applied to carbon steel and concrete surfaces inside Containment (e.g., steel liner, structural steel, supports, penetrations, and concrete walls and floors) will serve to prevent or minimize the loss of material of carbon steel components due to corrosion and aids in decontamination, but these coatings are not credited for managing the effects of corrosion for the carbon steel containment liner and components. This program ensures that the Service Level I coatings maintain adhesion so as to not affect the intended function of the emergency core cooling systems (ECCS) suction strainers.

The program also provides controls over the amount of unqualified coatings. Unqualified coating may fail in a way to affect the intended function of the ECCS suction strainers. Therefore, the quantity of degraded and unqualified coating is controlled and assessed periodically to ensure that the amount of unqualified coating in the primary containment is kept within acceptable design limits to support the post-accident operability of the ECCS.

NUREG-2191 Consistency

The *Protective Coating Monitoring and Maintenance* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.S8, Protective Coating Monitoring and Maintenance.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Monitoring and Trending (Element 5)

1. Procedures will be revised to require that a pre-inspection review of the previous "two" condition assessment reports be performed prior to each refueling outage.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Protective Coating Monitoring and Maintenance* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In October 2006, during an Engineering walkdown, Service Level I coating degradation and external corrosion was observed on a Unit 1 component cooling pipe inside Containment at the penetration area. Engineering selected two eighteen inch lines and two six inch lines with the most external corrosion for non-destructive examination (NDE) inspection. The identified pipes were cleaned and an NDE inspection measured the wall thickness to be greater than minimum wall thickness. Based on the results, no repair of the component cooling pipe was recommended. Work orders were created to restore the coating. On-going walkdowns performed routinely by the system engineer identified general corrosion and coating degradation of the component cooling piping throughout both Containments.

   Due to the extent of the degradation of Service Level I coatings on component cooling piping identified in October 2006, Engineering developed a program for monitoring and trending component cooling piping external corrosion rates. A separate prioritized action plan was developed for each unit. To maintain a meaningful component cooling pipe monitoring program, the component cooling pipe coating inside both Containments was restored to retard the continuing and accelerating pipe degradation, preserve the remaining component cooling pipe wall thickness, and assure long term component cooling pipe integrity. The Management Plan developed and funded a component cooling pipe and pipe coating restoration project so that a subsequent meaningful monitoring plan could be established. The restoration project was completed in June 2008.

2. In November 2009, coating inspections of the Containment steel liner were performed during the Unit 2 refueling outage (RFO). In general, the containment steel liner condition showed little mechanical damage. No degradation of the steel liner itself was noted during these inspections. There was very little Service Level I coating failure on the concrete surfaces in RCP cubicle 'B', Pressurizer Cubicle, and Loop Rooms. Degraded Service Level I coatings

were observed on component cooling piping. The subsequent inspections and Containment walkdowns were performed May 2011 during the Unit 2 RFO. An engineering walkdown was performed and the steel liner steel required coatings to be applied at various locations. Unqualified coatings were identified on the basement concrete joints in the form of spray paint at various locations. Unqualified coating was removed from the basement joint material resulting in a reduction of unqualified coating margin. The Containment Service Level I coating repairs were completed during the refueling outage.

3. In July 2012, during RFO 1R25, various areas of the Unit 1 Containment steel liner required coating repairs on each elevation. The Unit 1 coatings condition assessment was completed during RFO 1R24 and concluded there were no noticeable changes in the general condition from the condition noted during the fall 2010 refueling outage inspection. A walkdown of the coatings and steel liner in the Unit 1 Containment was performed by Engineering, which included a Coating Specialist and an ASME Code, Section XI, Subsection IWE, program Engineer. No relevant Service Level I coating indications were noted on the Containment liner or other surfaces with Service Level 1 coating that would affect the intended function of the ECCS suction strainers. The Containment steel liner Service Level I coatings repairs were completed in November 2013. The April 2015 Unit 1 R26 refueling outage Containment Coatings Assessment identified the Containment steel liner requires coating repairs be performed at various locations. The damaged areas were the result of mechanical damage.

4. In November 2015, during the Unit 2 refueling outage, visual examination of the Containment steel liner, along the concrete-liner interface of the Unit 2 Containment, was performed per ASME Code, Section XI, Subsection IWE. Areas with degraded Service Level I coatings were identified on the concrete-liner interface along the back of the Containment sump. Coated areas were examined for evidence of flaking, blistering, peeling, discoloration, and other signs of distress. The VT-1 examination did not reveal any adverse condition other than surface corrosion in the area identified. The Service Level I coating repairs in the Containment sump were completed in December 2015. A follow-up inspection of the Service Level I coating repair to the Containment steel liner to concrete floor interface identified two areas behind the inside recirculation spray pump suction header supports which required further Service Level I coatings repair. This was not a functionality issue. These were considered cosmetic issues proven by the completed satisfactory NDE examinations using UT thickness measurements technique and visual examination (VT-1) which did not reveal any adverse condition other than surface corrosion in the area identified. The Containment steel liner Service Level I coatings repairs were completed in November 2015. A Containment Coatings Walkdown was performed during the Spring Unit 2 2017 refueling outage. There were no noticeable changes in the general condition from the condition noted during the Fall 2015 refueling outage. The liner along various elevations continues to display marred sites to bare metal as the result of mechanical damage.

The above examples of operating experience provide objective evidence that the *Protective Coating Monitoring and Maintenance* program includes activities to perform visual inspections to manage loss of coating integrity for Service level 1 coatings, and to initiate corrective actions. Occurrences identified under the *Protective Coating Monitoring and Maintenance* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Protective Coating Monitoring and Maintenance* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Protective Coating Monitoring and Maintenance* program, following enhancement, will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.39 Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is an existing condition monitoring program that manages the aging effect of reduced electrical insulation resistance of inaccessible medium-voltage cables (operating voltages of 2kV to 35kV) exposed to significant moisture.

The program applies to inaccessible or underground non-EQ medium-voltage power cable installations (e.g., installed in buried conduits, duct banks, underground vaults, manholes, cable trenches or direct buried installations), within the scope of subsequent license renewal exposed to significant moisture. Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period), that if left unmanaged, could potentially lead to a loss of intended function. Power cable exposure to significant moisture may cause reduced electrical insulation resistance that can potentially lead to failure of the cable's insulation system.

Periodic actions are taken to prevent non-EQ inaccessible medium-voltage power cables from being exposed to significant moisture. Accessible cable conduit ends and manhole/vaults associated with cables included in this program are inspected for water collection and the water is drained, as necessary. Manholes associated with in-scope non-EQ inaccessible medium-voltage power cables are inspected to confirm that cables are not wetted or submerged in water, cables/vaults and cable support structures are intact and dewatering/drainage systems (i.e., sump pumps) and associated alarms operate properly. This inspection and water removal is performed based on actual plant experience over time with an inspection frequency being at least annually and after event driven occurrences (such as heavy rain, rapid thawing of ice and snow, or flooding). Dewatering devices and associated alarms are inspected and their operation verified periodically.

In-scope non-EQ inaccessible medium-voltage power cables routed through manholes, and duct banks are tested to detect reduced electrical insulation resistance of the cable's insulation system. Testing that is appropriate to the application at the time of the testing is performed. Cable testing includes one or more proven testing methods (such as dielectric loss [dissipation factor (Tan-Delta)/power factor], AC voltage withstand, partial discharge, step voltage, time domain reflectometry, insulation resistance and polarization index, or line resonance analysis). Cable testing acceptance criteria are defined prior to each test. Cables are tested at least once every six years. More frequent testing may occur based on test results and operating experience. <u>A plant-specific inaccessible medium-voltage cable test matrix that documents inspection methods,</u>

test methods, and acceptance criteria for the in-scope inaccessible medium-voltage power cables will be developed based on OE.

There are no submarine cables or other cables designed for continuous wetting or submergence currently in the scope of this program. Future installed cables of this design would be considered for inclusion in this program.

NUREG-2191 Consistency

The *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.E3A, Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Preventive Actions (Element 2)

1. Procedures will be revised to require inspection of in-scope manholes after event driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding.
2. Procedures will be revised to add a step stating that automatic or passive drainage features of manholes are operating properly.

Parameters Monitored/Inspected (Element 3)

3. A procedure will be created for testing medium-voltage cable that includes a requirement for testing medium-voltage cables that are exposed to significant moisture to determine the condition of the electrical insulation.
4. Procedures will be revised to add a step to evaluate adjusting the inspection frequency of manholes based on plant-specific operating experience over time with water collection.

Detection of Aging Effects (Element 4)

5. A new recurring event and maintenance schedule will be created for testing the "A" RSST cables at least once every six years.
6. A new recurring event and maintenance schedule will be created for testing the "B" RSST cables at least once every six years.

7. A new recurring event and maintenance schedule will be created for testing the "C" RSST cables at least once every six years.
8. A new procedure will be created for testing medium-voltage cable that includes a requirement that the specific type of test performed will be a proven test, utilizing one or more tests such as dielectric loss (dissipation factor (Tan-Delta)/power factor), AC voltage withstand, partial discharge, step voltage, time domain reflectometry, insulation resistance and polarization index, or line resonance analysis, for detecting deterioration of the insulation system due to submergence (e.g., selected test is applicable to the specific cable construction: shielded and non-shielded, and the insulation material under test).
9. A plant-specific inaccessible medium-voltage cable test matrix that documents inspection methods, test methods, and acceptance criteria for the in-scope inaccessible medium-voltage power cables will be developed based on OE.

Monitoring and Trending (Element 5)

10. A new procedure will be created for testing medium-voltage cable that includes a requirement to review visual inspection and physical test results that are trendable and repeatable to provide additional information on the rate of cable or connection insulation degradation.

Acceptance Criteria (Element 6)

11. A new procedure will be created for testing medium-voltage cable that includes acceptance criteria for tests and inspections.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program, has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In May 2009, following rain, water was observed draining out of the AAC cabling lead box located outside the condensate polishing building. A walkdown of the installation and a review of drawings was performed. An inspection of the ductlines entering the lead box discovered water in the ductlines. The ductlines were dewatered. Additionally, the individual ductlines were sealed, and the 4kV cables from the AAC diesel generator were entered into the cable life cycle management plan for testing. No wetting/degradation has been observed in recent inspections.

2. In September 2012, during an NRC review of License Renewal (LR) commitments and activities, the NRC LR review team identified that the proposed method to perform an annual visual inspection for water accumulation in an in-scope manhole may not be effective.

   The 'C' RSST power cable was re-routed to this manhole in April 2009. This was the only medium-voltage cable within the scope of initial license renewal.

   It was identified that the manhole was not being periodically inspected for water accumulation. As a result, the inspection procedure was revised to add the in-scope manhole. Additionally, it was noted that the procedure did not allow for manhole entry to attempt a visual inspection of this 42 foot deep manhole.

   It was determined that the use of a boroscope would be effective to provide for the necessary inspection. The procedure was revised accordingly.

3. In December 2015, an effectiveness review of the Non-Environmental Qualification (EQ) Cable Monitoring Activity (UFSAR Section 18.1.4) was performed. The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the detection of Aging Effects, Corrective Actions, and Operating Experience program elements. The Non-Environmental Qualification (EQ) Cable Monitoring AMA includes elements of the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.37), the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program (B2.1.38) and the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.39).

   During this effectiveness review, timeliness of corrective action for sealing duct bank entrances for the underground 'C' RSST cables was identified. A Work Order that was created in 2011 to seal the duct bank entrances in order to prevent water and silt entry into a license renewal manhole had not been completed and there was no evaluation to allow delay of the work. Subsequently, an assessment was completed to evaluate whether any license renewal commitments were compromised by delay in implementing the work order. Annual visual inspections of the same license renewal manhole between 2013 and 2017 have found water level being controlled below the level of the cables such that the cables are not exposed to significant moisture, indicating that water in-leakage has not exceeded the capability of the sump pumps. No license renewal commitments were judged to be compromised. Duct bank seals were installed to correct this condition during the 2018 Fall refueling outage.

   Results of the December 2015 effectiveness review for the other two associated aging management programs are provided in the SLRA sections indicated above.

4. In September 2016, the periodic surveillances of an in-scope manhole for water intrusion were reviewed. Since March 2012, when the inspection procedure was established, there has been no excessive water in the manhole, and no long term wetting of the medium-voltage cables in this manhole.

   The in-scope medium-voltage cables have been tested with the following results:

   - In 2011, the SBO AAC diesel cables were tan-delta tested with satisfactory results. These cables have been entered into the medium-voltage testing program.
   - In 2012, the RSST feeder cables were tan-delta tested with satisfactory results.
   - In 2015, the EDG #1 cables were meggered and PI tested (non-shielded cable) with satisfactory results. They again were tested satisfactorily in 2017.

5. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

6. In November 2017, as part of oversight review activities, the Non-Environmental Qualification (EQ) Cable Monitoring Activity (UFSAR Section 18.1.4) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

7. In January 2018, an aging management program effectiveness review was performed of the Non-Environmental Qualification (EQ) Cable Monitoring Activity (UFSAR Section 18.1.4). Information from the summary of that effectiveness review is provided below:

   The implementing procedure for this activity includes instructions for the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.37), *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program (B2.1.38) and *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.39). This effectiveness review summary applies to the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.39).

The Non-Environmental Qualification (EQ) Cable Monitoring Activity is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. Key activities of the AMA that were reviewed included the selection of components to be inspected or tested, the inspection and testing of the components, the evaluation of the inspection and testing results, repair/replacements of components as required, and AMA document updates. Engineering reports from the 2004/2006 and 2014/2016 inspection results of manholes containing in-scope medium-voltage cables were reviewed to confirm inspection frequencies were conducted at appropriate intervals and corrective actions taken consistent with the observed condition, such as raising cables from the bottom of the manhole when they were lying in water. The review also encompassed pertinent issues found in the Corrective Action Program from 2006 through 2017 for manhole water intrusion for those components within the scope of license renewal.

Due to the review of corrective actions to address wetted or submerged medium-voltage cables, the implementing procedure was enhanced to ensure manhole visual inspections are conducted at least annually and ensure the use of boroscopes to verify cables within the scope of license renewal were not exposed to submerged conditions when manholes cannot be entered.

The above examples of operating experience provide objective evidence that the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program includes activities to perform testing and visual inspections of manholes to identify the aging effect of reduced electrical insulation resistance for non-EQ inaccessible medium-voltage cables (operating voltage of 2kV to 35kV) exposed to significant moisture within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program, following enhancement, will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

a. Fluence Regions:

1) $\Phi t < 1x10^{20}$ n/cm^2
2) $1x10^{20}$ n/cm$^2 \leq \Phi t < 7x10^{20}$ n/cm^2
3) $7x10^{20}$ n/cm$^2 \leq \Phi t < 1x10^{21}$ n/cm^2
4) $1x10^{21}$ n/cm$^2 \leq \Phi t < 1x10^{22}$ n/cm^2
5) $1x10^{22}$ n/cm$^2 \leq \Phi t < 5x10^{22}$ n/cm^2
6) $5x10^{22}$ n/cm$^2 \leq \Phi t$

Notes:

1. Alloy 600 was identified as the material for the support pin nuts at Surry Unit 1. These nuts were replaced as part of the control rod guide tube support pin replacement performed by AREVA. The AREVA evaluation indicates that the Unit 1 support pin nuts are susceptible to age-related degradation
2. The upper core plate insert locking devices are 304L SS and the dowel pins are 316 SS.
3. No additional measures

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a]			Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
				MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022								
Lower internals assembly (cont.)	Core barrel	Core barrel flange (surface: upper flange weld is included below with upper core barrel girth welds)	304 SS	SCC-W, Wear	SCC-W, Wear	SCC-W, Wear, Fatigue	L	M	H	1	2	B	B	~~P~~ E
		Core barrel outlet nozzles	304 SS	SCC-W, Fatigue	SCC-W, Fatigue	SCC-W, Wear, Fatigue	L	M	H	1	2	B	B	E
		Lower core barrel axial welds (includes MAW ~~and LAW~~) Note 5	304 SS	SCC-W, IASCC, IE	SCC-W, IASCC, IE	SCC-W, IASCC, Fatigue, IE, VS	M	M	H	2	3	B	C	E
		Lower core barrel girth welds (includes LGW and LFW)	304 SS	SCC-W, IASCC, IE	SCC-W, IASCC, IE	SCC-W, IASCC, Fatigue, IE, VS	M	M	H	2	3	B	C	P
		Upper core barrel axial welds (includes UAW)	304 SS	SCC-W, IASCC, IE	SCC-W, IE	SCC-W, Fatigue	M	M	H	2	3	B	C	E
		Upper core barrel girth welds (includes UFW ~~and UGW~~) Note 5	304 SS	SCC-W, IASCC, IE	SCC-W, IE	SCC-W, Fatigue	M	M	H	2	3	B	C	P
	Diffuser plate	Diffuser plate (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N
	Flux thimble (tubes)	Flux thimble tube plugs (Note 3)	Alloy 600	--	SCC-W, IASCC, IE, VS	SCC-W, IASCC, Fatigue, IE, VS	M	L	L	2	2	B	B	N
		Flux thimbles (tubes)	Alloy 600	--	SCC-W, IASCC, Wear, IE, VS	SCC-W, IASCC, Wear, Fatigue, IE, VS	H	L	L	3	3	B	B	X
	Head cooling spray nozzles	Head cooling spray nozzles (Note 3)	304 SS	None	None	Fatigue	L	L	L	1	1	A	A	N

Table C3.3-3 SLR Expert Panel Review Results Table

Assembly	Sub-assembly	Component	Material	Screened-in Degradation Mechanisms[a]			Likelihood of Failure	Safety Consequence	Economic Consequence	Safety FMECA Group	Economic FMECA Group	Safety Consequence Risk Category	Economic Consequence Risk Category	SLR Inspection Category[b]
				MRP-191, Rev. 0	MRP-191, Rev. 1	Expert Panel [c] / MRP 2018-022								
Lower internals assembly (cont.)	Radial support keys	Radial support key bolts (Note 3)	316 SS	--	Wear	Fatigue	L	L	L	1	1	A	A	N
		Radial support key dowels (Note 3)	304 SS	--	--	Fatigue	L	L	L	1	1	A	A	N
			316 SS	--	--	Fatigue	L	L	L	1	1	A	A	N
		Radial support key lock keys (Note 3)	304 SS	None	None	Fatigue	L	L	L	1	1	A	A	N
		Radial support keys	304 SS	SCC-W, Wear	SCC-W, Wear	SCC-W, Wear, Fatigue	L	M	M	1	1	A	A	~~P~~ N
		Radial support keys	Stellite	--	--	Wear	H	M	M	3	3	C	C	P (added by IG)
	Secondary core support (SCS) assembly	SCS base plate (Note 3)	304 SS	SCC-W	SCC-W	SCC-W, Fatigue	L	L	L	1	1	A	A	N
		SCS bolts (Note 3)	316 SS	None	None	Fatigue	L	L	L	1	1	A	A	N
		SCS energy absorber (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N
		SCS guide post (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N
		SCS housing (Note 3)	304 SS	None	None	None	--	--	--	0	0	A	A	N
		SCS lock keys (Note 3)	304 SS	None	None	Fatigue	L	L	L	1	1	A	A	N
		Upper and lower tie plates (Note 3)	304 SS	--	None	Fatigue	L	L	L	1	1	A	A	N

a. Degradation mechanisms:
Stress corrosion cracking (SCC) [1A is applicable for SCC welds (SCC-W)]
Irradiation-assisted stress corrosion cracking (IASCC)
Wear
Fatigue (FAT)
Thermal aging embrittlement (TE)
Irradiation embrittlement (IE)
Void swelling (VS)
Thermal and irradiation-induced stress relaxation or irradiation creep (ISR/IC)

b. P = Primary, E = Expansion, X = Existing, N = No additional measures

c. Degradation mechanism added during Expert Panel review as indicated in LTR-AMLR-17-35 and LTR-AMLR-18-4.

Notes:

1. Alloy 600 was identified as the material for the support pin nuts at Surry Unit ~~1)~~. These nuts were replaced as part of the control rod guide tube support pin replacement performed by AREVA. The AREVA evaluation indicates that the aging degradation mechanisms of concern are SCC and irradiation-enhanced stress relaxation/irradiation-enhanced creep (ISR/IC).
2. The upper core plate insert locking devices are 304L SS, and the dowel pins are 316 SS.
3. No additional measures.
4. The thermal shield flexure locking devices are 304L SS and the dowel pins are 304 SS.
5. MRP-227, Revision 1, added expansion links from the upper flange weld (UFW) to the lower flange weld (LFW) and to the upper girth weld (UGW).

Table C3.3-4 Comparison: Risk Category Designations from MRP-191, Revision 1, and the Results from the SLR Expert Panel Review

Assembly	Subassembly	Component	Risk Categorization		
			MRP-191, Revision 1 Category	SLR Expert Panel Safety Category	SLR Expert Panel Economic Category
Lower internals assembly	Baffle and former assembly	Baffle bolting lock bars (Note 3)	A	B	B
		Baffle-edge bolts	C	B	C
		Baffle plates	B	A	A
		Baffle-former bolts	C	C	C
		Corner bolts	--	C	C
		Barrel-former bolts	C	B	C
		Former plates	B	A	A
	Bottom-mounted instrumentation (BMI) column assemblies	BMI column bodies	B	B	B
		BMI column bolts (Note 3)	A	B	B
		BMI column collars (Note 3)	B	B	B
		BMI column cruciform (Note 3)	B	B	B
		BMI column extension bars (Note 3)	A	A	A
		BMI column extension tubes (Note 3)	B	A	A
		BMI column locking devices (Note 3)	A	A	A
		BMI column nuts (Note 3)	A	A	A
	Core barrel	Core barrel flange (surface)	B	B	B
		Core barrel outlet nozzles	B	B	B
		Lower core barrel axial welds (includes MAW and LAW)	C	B	C
		Lower core barrel girth welds (includes LGW and LFW)	C	B	C
		Upper core barrel axial welds (includes UAW)	C	B	C
		Upper core barrel girth welds (includes UFW and UGW)	C	B	C
	Diffuser plate	Diffuser plate (Note 3)	A	A	A
	Flux thimble (tubes)	Flux thimble tube plugs (Note 3)	B	B	B
		Flux thimbles (tubes)	C	B	B
	Head cooling spray nozzles	Head cooling spray nozzles (Note 3)	A	A	A
	Irradiation specimen guides	Irradiation specimen access plug (dowel pin) (Note 3)	--	A	A
		Irradiation specimen access plug (plug) (Note 3)	A	A	A
		Irradiation specimen access plug (spring) (Note 3)	--	A	A
		Irradiation specimen guide (Note 3)	A	A	A

Table C3.3-4 Comparison: Risk Category Designations from MRP-191, Revision 1, and the Results from the SLR Expert Panel Review

Assembly	Subassembly	Component		Risk Categorization		
				MRP-191, Revision 1 Category	SLR Expert Panel Safety Category	SLR Expert Panel Economic Category
Interfacing components	Interfacing components	Clevis insert bolts		B	B	C
		Clevis insert dowels		--	B	B
		Clevis insert locking devices (Note 3)		A	A	A
		Clevis inserts	Alloy 600	A	A	B
			Stellite	A	C	C
		Head and vessel alignment pin bolts (Note 3)		A	A	A
		Head and vessel alignment pins (Note 3)		A	A	A
		Internals hold-down spring		B	B	C
		Upper core plate alignment pins	304 SS	B	A	A
			Stellite	--	A	B
		Thermal sleeves		--	C	C
		Thermal sleeve guide funnels (Note 3)		--	B	B

Notes:

1 Alloy 600 was identified as the material for the support pin nuts at Surry Unit 1. These nuts were replaced as part of the control rod guide tube support pin replacement performed by AREVA. ~~AREVA performed an assessment of the CRGT support pins nuts for Surry Unit 1 and determined that no additional action is necessary to conform to MRP 227 A guidelines for the period of extended operation.~~The AREVA evaluation indicates that the Unit 1 support pin nuts are susceptible to age-related degradation.

2 The upper core plate insert locking devices are 304L SS and the dowel pins are 316 SS.

3 No additional measures

Table C4.3-2 Expansion Components

Expansion Item	Effect (mechanism)	Primary Link (Note 1)	Examination Method / Frequency	Examination Coverage	Source of Revision/ Addition
Core Barrel Assembly Lower flange weld (LFW)	Cracking (SCC)	Upper core barrel flange weld (UFW).	Enhanced visual (EVT-1) examination. Re-inspection every 10 years following initial inspection.	100% of the accessible weld length of the OD surface of the LFW and 0.75-inch of adjacent base metal shall be examined. (Note 9)	MRP-227, Revision 1, added the LFW to the Expansion category as a link from Primary-Upper flange weld (UFW). MRP 2018-026 changed the examination coverage.
Core Barrel Assembly Upper axial weld (UAW)	Cracking (SCC, IASCC) Irradiation Embrittlement (IE) is an applicable aging mechanism.	Upper core barrel flange weld (UFW).	Enhanced visual (EVT-1) examination. Re-inspection every 10 years following initial inspection.	100% of the accessible weld length of one side of the UAW and ¾' of adjacent base metal shall be examined (Note 9)	MRP-227, Revision 1, added the UAW to the Expansion category as a link from Primary-Upper flange weld (UFW). MRP 2018-026 changed the examination coverage.
Lower Internals Assembly Lower support forging	Cracking (SCC)	Upper Core Barrel Flange Weld (UFW) (Note 2)	Visual (~~VT-3~~EVT-1) examination. Re-inspection every 10 years following initial inspection. (Note 3)	25% of the bottom surface. (Notes 4 and 5)	MRP-227, Revision 1, added this item to the Expansion category. MRP 2018-022 specified VT-3 examination and 25% coverage.
Lower Support Assembly Lower support column bodies (cast)	Cracking (IASCC) including detection of completely fractured column bodies. Irradiation Embrittlement (IE) is an applicable aging mechanism.	Lower core barrel girth Weld (Note 2)	Visual (~~VT-3~~EVT-1) examination. Re-inspection every 10 years following initial inspection. (Note 3)	25% of accessible support column assemblies as visible from above the lower core plate. (Note 4)	MRP-227, Revision 1, added this item to the Expansion category. MRP 2018-022 specified VT-3 examination and 25% coverage.
Core Barrel Assembly Barrel-former bolts (Note 7)	Cracking (IASCC, Fatigue) Irradiation Embrittlement (IE), void swelling, irradiation-enhanced stress relaxation (ISR) aging mechanisms	Baffle-former bolts	Volumetric (UT) examination Re-inspection every 10 years following initial inspection.	100% of accessible barrel-former bolts (minimum of 75% of the total population). Accessibility may be limited by presence of thermal shield or neutron pads. (Note 4)	MRP-227A

Table C4.3-3 Existing Programs Components

Item	Effect (mechanism)	Reference	Examination Method[a]	Examination Coverage	Source of Revision/ Addition
Control Rod Guide Tube Assembly Guide tube support pins and support pin nuts (Unit 1 only)	Cracking (SCC, Fatigue) Loss of material (wear) Irradiation embrittlement (IE) and Thermal and irradiation-induced stress relaxation (ISR/IC) are applicable aging mechanisms.	ASME Code Section XI	Visual (VT-3) examination	All accessible surfaces at specified frequency	MRP-227A
Core Barrel Assembly Core barrel flange (surface)	Loss of material (wear)	ASME Code Section XI, Category B-N-3	Visual (VT-3) exam to determine general condition for excessive wear.	All accessible surfaces at specified frequency.	MRP-227A
Upper Internals Assembly Upper support ring	Cracking (SCC, Fatigue)	ASME Code Section XI, Category B-N-3	Visual (VT-3) examination.	All accessible surfaces at specified frequency.	MRP-227A
Upper Internals Assembly Fuel alignment pins (Malcomized)	Loss of material (wear)	ASME Code Section XI	Visual (VT-3) examination	All accessible surfaces at specified frequency.	Added by MRP 2018-022. See TB-16-4.
Lower Internals Assembly Lower core plate	Cracking (IASCC, Fatigue) Irradiation Embrittlement (IE) is an applicable aging mechanism.	ASME Code Section XI, Category B-N-3	Visual (VT-3) exam of the lower core plate to detect evidence of distortion and/or loss of bolt integrity.	All accessible surfaces at specified frequency.	Clarified with separate item created for wear by Rev. 1.
Lower Internals Assembly Lower core plate	Loss of material (wear)	ASME Code Section XI	Visual (VT-3) examination	All accessible surfaces at specified frequency.	Clarified with separate item created for wear by Rev. 1.
Lower Internals Assembly Fuel alignment pins (Malcomized)	Loss of material (wear)	ASME Code Section XI	Visual (VT-3) examination	All accessible surfaces at specified frequency.	Added by MRP 2018-022. See TB-16-4.
Bottom Mounted Instrumentation System Flux thimble tubes	Loss of material (wear)	IEB 88-09; Surry Augmented Inspection Program	Surface (ECT) examination.[b]	Eddy current surface examination for 100% of the accessible thimbles.	MRP-227A
Alignment and Interfacing Components Upper core plate alignment pins	Loss of material (wear).	ASME Code Section XI	Visual (VT-3) examination.	All accessible surfaces at specified frequency.	MRP-227A

a. Inspections for the components listed for Unit 1 were completed in November 2013. Inspections performed for Unit 2 were completed in May 2014.