FPL

L-2018-152
10 CFR 54.17

August 31, 2018

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

Re: Florida Power & Light Company
Turkey Point Units 3 and 4
Docket Nos. 50-250 and 50-251
Turkey Point Units 3 and 4 Subsequent License Renewal Application
Safety Review Requests for Additional Information (RAI) Set 1 Responses

References:

1. FPL Letter L-2018-004 to NRC dated January 30, 2018, Turkey Point Units 3 and 4 Subsequent License Renewal Application (ADAMS Accession No. ML18037A812)
2. FPL Letter L-2018-082 to NRC dated April 10, 2018, Turkey Point Units 3 and 4 Subsequent License Renewal Application – Revision 1 (ADAMS Accession No. ML18113A134)
3. NRC RAI E-Mail to FPL dated August 6, 2018, Requests for Additional Information for the Safety Review of the Turkey Point Subsequent License Renewal Application – Set 1 (EPID No. L-2018-RNW-0002) (ADAMS Accession Nos. ML18218A199 and ML18218A200)

Florida Power & Light Company (FPL) submitted a subsequent license renewal application (SLRA) for Turkey Point Units 3 and 4 to the NRC on January 30, 2018 (Reference 1) and SLRA Revision 1 on April 10, 2018 (Reference 2).

The purpose of this letter is to provide, as attachments to this letter, responses to the safety review RAIs issued by the NRC on August 6, 2018 (Reference 3). Each RAI response and its corresponding attachment are indexed on page 2 of this letter. The attachments identify changes that will be made in a future revision of the SLRA (if applicable).

If you have any questions, or need additional information, please contact me at 561-691-2294.

A084
NRR

I declare under penalty of perjury that the foregoing is true and correct.

Executed on August 31, 2018.

Sincerely,

William Maher
Senior Licensing Director
Florida Power & Light Company

WDM/RFO

Attachments: 18 RAI Responses (refer to Letter Attachment Index)

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Plant Project Manager, USNRC, SLRA
Plant Project Manager, USNRC, SLRA Environmental
Ms. Cindy Becker, Florida Department of Health

NRC RAI Letter No. ML18218A199 Dated August 6, 2018

1. No Aging Effects – Mechanical Components

Regulatory Basis:

Section 54.21(a)(3) of Title 10 of the *Code of Federal Regulation* (10 CFR) requires an applicant to demonstrate that the effects of aging for structures and components will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. One of the findings that the staff must make to issue a renewed license (10 CFR § 54.29(a)) is that actions have been identified and have been or will be taken with respect to the managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under § 54.21, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis (CLB). As described in SRP-SLR, an applicant may demonstrate compliance with 10 CFR 54.21(a)(3) by referencing NUREG-2191, Rev. 0, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report," dated July 2017. In order to complete its review and enable making a finding under 10 CFR § 54.29(a), the staff requires additional information in regard to the matters described below.

RAI 3.1.2.2.15-1

Background:

SLRA Section 3.1.2.2.15, associated with SLRA Table 3.1.1, items 3.1.1-105 and 3.1.1-115, states that:

> There are no reactor coolant system stainless steel or steel piping or piping components, within the scope of subsequent license renewal, exposed to concrete at Turkey Point. Where reactor coolant system piping is required to penetrate concrete, penetration sleeves are used. This is addressed further in Section 3.5.

NUREG-2192, Rev. 0, "Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants" (SRP-SLR), dated July 2017 (SRP-SLR), Section 3.1.2.2.15 states that there are three conditions associated with determining that there are no aging effects for steel piping exposed to concrete:

> (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.

SLRA Section 3.3.2.2.9 documents that, "[t]he concrete at Turkey Point is designed and constructed in accordance with ACI 318-63 using ingredients/materials conforming to ACI and ASTM standards."

SRP-SLR Section 3.1.2.2.15 states that there is one condition associated with determining that there are no aging effects for stainless steel piping exposed to concrete, that being, the piping is not potentially exposed to groundwater.

Issue:

For steel piping the response to SLRA Section 3.3.2.2.9 does not provide the results of a search of plant-specific OE demonstrating that there are no instances where degradation of the concrete that could lead to penetration of water to the metal surface occurred. However, SLRA Table 3.3-1, aging management review (AMR) item 3.31-112 states, "A review of OE [operating experience] for Turkey Point indicates there are occurrences of concrete degradation that could lead to the penetration of water to the metal surface..."

For both stainless steel and steel piping, the response to SLRA Section 3.3.2.2.9 does not state whether the piping could be exposed to groundwater.

There does not appear to be any further discussion of reactor coolant piping penetrating concrete through penetration sleeves. The discussions related to sleeves in Section 3.5 are associated with containment penetrations and the associated time limiting aging analyses.

Request:

Address criterion (b) and (c) for steel piping, noting that criterion (b) addresses any type of water penetrating through the concrete and criterion and (c) specifically addresses groundwater.

State whether the stainless steel piping could be exposed to groundwater.

FPL Response:

(b) Steel piping in concrete at PTN is the gray cast iron drains in the Waste Disposal system, as listed in SLRA Table 3.3.2-8. These drains are subject to a loss of material that is managed by the Buried and Underground Piping and Tanks AMP. The fourth sentence of the PTN specific portion of SLRA Section 3.3.2.2.9 states, "A review of OE for Turkey Point indicates there are occurrences of concrete degradation that could lead to the penetration of water to the metal surface; therefore, a loss of material due to general, pitting and crevice corrosion of steel piping and tanks exposed to concrete is an aging effect that requires management". This concrete degradation, internal to auxiliary building, is further described in SLRA Section B.2.3.35. As such, the type of water that could penetrate degraded concrete is leakage or spills inside the building.

(c) Criterion c was not addressed in SLRA Section 3.3.2.2.9 as the failure to meet criterion b qualified loss of material as an applicable aging effect for steel in concrete. The slab of the auxiliary building is identified through a PTN OE search to be potentially susceptible to penetration by groundwater. However, the waste disposal piping is not embedded in the slab, all drains are gravity fed to the waste disposal tank and any waste collection below the waste disposal tank is collected

through sump pumps.

Degradation of concrete which may allow water to penetrate and contact the surface of embedded components has been identified at PTN. For the concrete containment and auxiliary building base slabs, this susceptibility may allow groundwater to penetrate. However, there is no piping, within the scope of license renewal, embedded in the containment or auxiliary building base slabs. There is no stainless steel piping in concrete at PTN that could be exposed to groundwater.

The PTN specific portion of SLRA Section 3.3.2.2.9 is clarified as shown in the Associated SLRA Revisions section below. In addition, in reviewing the relevant portions of the PTN SLRA, several items in Table 3.2-1 were found to be inconsistent. Corrections to this table are also found in the Associated SLRA Revisions section below.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Section 3.3.2.2.9 and Table 3.2-1 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Revise SLRA Section 3.3.2.2.9 as follows:

3.3.2.2.9 Loss of Material Due to General, Crevice or Pitting Corrosion and Cracking Due to Stress Corrosion Cracking

Loss of material due to general (steel only), crevice, or pitting corrosion, and cracking due to SCC (SS only) can occur in steel and SS piping and piping components exposed to concrete. Concrete provides a high alkalinity environment that can mitigate the effects of loss of material for steel piping, thereby significantly reducing the corrosion rate. However, if water intrudes through the concrete, the pH can be reduced and ions that promote loss of material such as chlorides, which can penetrate the protective oxide layer created in the high alkalinity environment, can reach the surface of the metal. Carbonation can reduce the pH within concrete. The rate of carbonation is reduced by using concrete with a low water-to-cement ratio and low permeability. Concrete with low permeability also reduces the potential for the penetration of water. Adequate air entrainment improves the ability of the concrete to resist freezing and thawing cycles and therefore reduces the potential for cracking and intrusion of water. Cracking due to SCC, as well as pitting and crevice corrosion can occur due to halides present in the water that penetrates to the surface of the metal.

If the following conditions are met, loss of material is not considered to be an applicable aging effect for steel: (a) attributes of the concrete are consistent with American Concrete Institute (ACI) 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG–1557; (b) plant

specific OE indicates no degradation of the concrete that could lead to penetration of water to the metal surface; and (c) the piping is not potentially exposed to groundwater. For SS components, loss of material and cracking due to SCC are not considered to be applicable aging effects as long as the piping is not potentially exposed to groundwater. Where these conditions are not met, loss of material due to general (steel only), crevice, or pitting corrosion, and cracking due to SCC (SS only) are identified as applicable aging effects. GALL-SLR Report AMP XI.M41, "Buried and Underground Piping and Tanks," describes an acceptable program to manage these aging effects.

The Auxiliary Systems include~~s both~~ steel **(gray cast iron)** and stainless steel piping and **steel** tanks exposed to concrete. The concrete at Turkey Point is designed and constructed in accordance with ACI 318-63 using ingredients/materials conforming to ACI and ASTM standards. ~~The stainless steel components are above groundwater and, therefore, do not require management as detailed above.~~ A review of OE for Turkey Point indicates there are occurrences of concrete degradation that could lead to the penetration of water to the metal surface~~;~~**. Additionally, a review of OE for Turkey Point has shown that the concrete base slabs of the containment and the auxiliary building may allow groundwater penetration.** ~~therefore, a~~ **However, there is no piping, within the scope of license renewal, embedded in the containment or auxiliary building base slabs. A** loss of material due to general, pitting, and crevice corrosion of steel piping and tanks exposed to concrete is an aging effect that requires management **based on the potential for system leakage or spills penetrating degraded auxiliary building concrete.**

Consistent with the recommendation of GALL-SLR, the Buried and Underground Piping and Tanks AMP is used to manage loss of material in steel piping exposed to concrete. This AMP provides for the management of aging effects through periodic visual inspection. Any visual evidence of loss of material will be evaluated for acceptability. Deficiencies will be documented in accordance with the 10 CFR Part 50, Appendix B Corrective Action Program. The Buried and Underground Piping and Tanks AMP is described in Appendix B.

Loss of material and cracking are not considered applicable aging effects for stainless steel components at PTN exposed to concrete since there are no instances where they would be potentially exposed to groundwater.

Revise SLRA Table 3.2-1 as follows:

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Program (AMP)/TLAA	Further Evaluation Recommended	Discussion
3.2-1, 053	Stainless steel, nickel alloy piping, piping components, tanks, exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. ~~The Engineered Safety Features system does not include any buried or underground piping or tanks exposed to soil or concrete.~~ **<u>As the stainless steel piping exposed to concrete in the Engineered Safety Features systems is not exposed to ground water, there are no aging effects that require management.</u>** Note that underground piping in the safety injection system is in an underground trench and not directly exposed to soil ~~or concrete~~. This piping is managed using the Buried and Underground Piping and Tanks AMP and is associated with item number 3.2-1, 080.
3.2-1, 078	Stainless steel, steel, aluminum piping, piping components, tanks exposed to soil, concrete	Cracking due to SCC (steel in carbonate/ bicarbonate environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Not applicable. ~~The Engineered Safety Features systems do not include any steel, stainless steel, or aluminum piping, piping components, or tanks that are exposed to soil or concrete and within the scope of the Buried and Underground Piping and Tanks AMP.~~ **<u>As the stainless steel</u>**

					piping exposed to concrete in the Engineered Safety Features systems is not exposed to ground water, there are no aging effects that require management. Note that underground piping in the safety injection system is in an underground trench and not directly exposed to soil. This piping is managed using the Buried and Underground Piping and Tanks AMP and is associated with item number 3.2-1, 080.

Associated Enclosures:

None

NRC RAI Letter No. ML18218A199 Dated August 6, 2018

RAI 3.3.2.1.4-1

Background:

SLRA AMR items 3.3.1-114 and 3.4.1-054 state that copper alloy piping and piping components exposed to air, condensation, or gas have no aging effects requiring management.

Several SLRA Table 2 AMR items, associated with AMR items 3.3.1-114 and 3.4.1-054, cite copper alloy greater than 15 percent zinc components exposed to air-dry, air-indoor controlled, air-indoor uncontrolled, air-outdoor, condensation, and gas as having no aging effects requiring management.

For these copper alloy greater than 15 percent zinc components: (a) one of these AMR items (SLRA Table 3.3.2-4), associated with gas as the environment, plant-specific note 2 states that the piping component is wetted; and (b) for two of these AMR items (SLRA Table 3.3.2-16), the component is identified as heat exchanger tubes.

GALL-SLR AMR items S-454 and S-455 recommend that cracking due to stress corrosion cracking (SCC) be managed for copper alloy greater than 15 percent zinc piping, piping components, and tanks exposed to air or condensation.

Issue:

SRP-SLR AMR items 3.3.1-114 and 3.4.1-054 are only applicable to copper alloy components, not copper alloy greater than 15 percent zinc components. No basis was provided for why cracking is not an applicable aging effect for copper alloy greater than 15 percent zinc component exposed to air-dry, air-indoor controlled, air-indoor uncontrolled, air-outdoor, or condensation.

Although the GALL-SLR Report does not address copper alloy greater than 15 percent zinc components exposed to gas, it would not be expected that cracking would occur in this environment due to the unlikely presence of ammonia-based compounds in the gas. However, the staff lacks sufficient information to come to this conclusion due to the potential for the piping component to be wetted.

It is unclear how cracking will be managed for heat exchanger tubes due to the inaccessibility of the internal and external surfaces for inspection types cited in the SLRA aging management programs (AMPs) (e.g., Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program, External Surfaces Monitoring of Mechanical Components program).

Request:

a) State the basis for why cracking is not an applicable aging effect for copper alloy greater than 15 percent zinc components exposed to air-dry, air-indoor controlled, air-indoor uncontrolled, air-outdoor, or condensation.

b) State the basis for why the source of the moisture that wets the surface of the piping component exposed to gas in SLRA Table 3.3.2-4 will not induce cracking.

If cracking needs to be managed for the heat exchanger tubes, state the inspection method(s) that will be used and the applicable AMP.

FPL Response:

a) Cracking is not an applicable aging effect for copper alloy greater than 15% zinc components exposed to dry air or controlled indoor air. Consistent with NUREG-2191, the only aging effect for metallic components, including copper alloy greater than 15% zinc, in a dry air environment is loss of material. Loss of material for metallic components in an air-dry environment is managed by the Compressed Air Monitoring AMP, as described in SLRA item 3.3-1, 235. There are no instances of copper alloy greater than 15% zinc components in an environment of air-indoor controlled at PTN.

Cracking was not considered an applicable aging effect for copper alloy greater than 15% zinc components exposed to air-indoor uncontrolled, air-outdoor or condensation as there is not expected to be ammonia present in the atmosphere, nor has PTN OE shown any indications of degradation tied to ammonia in any environment. However, as the air-indoor uncontrolled and air-outdoor environments are not controlled to exclude the presence of ammonia, it is conservative for ammonia to be potentially present that can induce cracking and it is managed by the External Surfaces Monitoring of Mechanical Components AMP. Appropriate line items are revised or added for copper alloy greater than 15% zinc components exposed to air-indoor uncontrolled and air-outdoor and condensation environments. These changes are shown in the Associated SLRA Revisions section below.

Several of the components now recognized to be susceptible to cracking are heat exchanger tubes. Fourteen of these heat exchangers are the normal and emergency containment cooling heat exchangers exposed to condensation, and four of the heat exchangers are the radiator for each emergency diesel generator and are exposed to air – indoor uncontrolled. Eight of the heat exchangers are the emergency diesel generator turbocharger aftercooler exposed to air – outdoor. As such, the tubes are inside a housing and the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP is applicable for aging management.

Inspection methods for heat exchanger tubes are discussed in response to RAI 3.2.2.2.2-1.

b) The piping component exposed to wetted gas (treated as condensation to account for moisture) is the volume control tank relief valve. The valve is exposed to the cover gas region of the tank, which is partially filled with reactor coolant. Per a review of PTN OE, the RCS may contain ammonia due to hydrazine degrading into ammonia and ammonium compounds being used for pH control. The PTN OE does not show any evidence of cracking or degradation associated with ammonia.

However, as the ammonia concentration is not explicitly known, it is prudent to consider ammonia to be potentially present in the RCS in concentrations which can induce cracking. AMR item 3.3-1, 132 is used for the volume control tank relief valve. This change is shown in the Associated SLRA Revisions section under the Table 3.3.2-4 changes.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Table 3.2-1, Table 3.2.2-1, Table 3.3-1, Table 3.3.2-1, Table 3.3.2-2, Table 3.3.2-4, Table 3.3.2-10, Table 3.3.2-15, Table 3.3.2-16, Table 3.4-1, and Table 3.4.2-1 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Revise SLRA Table 3.2-1 Item 071 as follows:

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 071	Insulated copper alloy (>15% Zn or >8% Al) piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	~~Not applicable.~~ ~~The Engineered Safety Features systems do not include any insulated copper alloy piping, piping components, or tanks.~~ **This line item will be used to manage cracking of copper alloy >15% Zn or >8% Al heat exchanger tubes exposed to air, condensation. The heat exchanger tubes are located in a housing, as such the aging management program used associated with this line item is the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP.**

Revise SLRA Table 3.2.2-1 as follows:

Table 3.2.2-1: Emergency Containment Cooling – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Condensation (ext)	~~None~~Cracking	~~None~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	~~V.F.EP-10~~V.E.E-406	~~3.2-1, 057~~3.2-1, 071	~~A~~E

Revise SLRA Table 3.3-1 Item 132 as follows:

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 132	Insulated steel, copper alloy (>15% Zn or >8% Al), piping, piping components, tanks, tanks (within the scope of AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks") exposed to air, condensation	Loss of material due to general, pitting, crevice corrosion (steel only); cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components" or AMP XI.M29, "Outdoor and Large Atmospheric Metallic Storage Tanks"	No	Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components AMP is used to manage loss of material of steel and <u>cracking of</u> copper <u>alloy (>15% Zn or >8% Al)</u> insulated piping, piping components, and tanks exposed to air or condensation. <u>**This line item is also used for copper alloy (>15% Zn or >8% Al) heat exchanger tubes located in a housing, the internal surface of a copper alloy (>15% Zn or >8% Al) relief valve for each volume control tank exposed to condensation, and the internal surface of copper alloy (>15% Zn or >8% Al) fire protection nozzles, tubing and valve bodies exposed to air. The aging management program used for internal components associated with this line item is the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP.**</u>

Revise SLRA Table 3.3.2-1 as follows:

Table 3.3.2-1: Intake Cooling Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Copper alloy >8% Al	Air – outdoor (ext)	~~None~~**Cracking**	~~None~~**External Surfaces Monitoring of Mechanical Components**	~~VIII.I.SP-6~~**VII.I.A-405a**	~~3.2-1, 057~~**3.3-1, 132**	A

Revise SLRA Table 3.3.2-2 as follows:

Table 3.3.2-2: Component Cooling Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	~~Loss of material~~ **Cracking**	External Surfaces Monitoring of Mechanical Components	VII.I.A-405a	3.3-1, 132	A
~~Valve body~~	~~Pressure boundary~~	~~Copper alloy >15% Zn~~	~~Air – indoor uncontrolled (ext)~~	~~None~~	~~None~~	~~V.F.EP-10~~	~~3.2-1, 057~~	~~A~~

Revise SLRA Table 3.3.2-4 as follows:

Table 3.3.2-4: Chemical and Volume Control – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (shell)	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	~~None~~Cracking	~~None~~External Surfaces Monitoring of Mechanical Components	~~VII.J.AP-144~~VII.I.A-405a	~~3.3-1, 114~~3.3-1, 132	A
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	~~None~~Cracking	~~None~~External Surfaces Monitoring of Mechanical Components	~~VII.J.AP-144~~VII.I.A-405a	~~3.3-1, 114~~3.3-1, 132	A
Valve body	Pressure boundary	Copper alloy >15% Zn	Condensation (int)	~~None~~Cracking	~~None~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	~~VII.J.AP-144~~ VII.I.A-405a	~~3.3-1, 114~~3.3-1, 132	~~A~~E, 2

Revise SLRA Table 3.3.2-10 as follows:

Table 3.3.2-10: Normal Containment Ventilation – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Condensation (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.I.A-405a	3.3-1, 132	E

Revise SLRA Table 3.3.2-15 as follows:

Table 3.3.2-15: Fire Protection – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (channel head)	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	~~None~~Cracking	~~None~~External Surfaces Monitoring of Mechanical Components	~~VII.J.AP-144~~VII.I.A-405a	~~3.3-1, 114~~3.3-1, 132	A
Nozzle	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	~~None~~Cracking	~~None~~External Surfaces Monitoring of Mechanical Components	~~VII.J.AP-144~~VII.I.A-405a	~~3.3-1, 114~~3.3-1, 132	A

Table 3.3.2-15: Fire Protection – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Nozzle	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (int)	~~None~~**Cracking**	~~None~~**Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	~~VII.J.AP-144~~**VII.I.A-405a**	~~3.3-1, 114~~**3.3-1, 132**	~~A~~**E**
Nozzle	Pressure boundary	Copper alloy >15% Zn	Air – outdoor (ext)	~~None~~**Cracking**	~~None~~**External Surfaces Monitoring of Mechanical Components**	~~VII.J.AP-144~~**VII.I.A-405a**	~~3.3-1, 114~~**3.3-1, 132**	A
Nozzle	Pressure boundary	Copper alloy >15% Zn	Air – outdoor (int)	~~None~~**Cracking**	~~None~~**Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	~~VII.J.AP-144~~**VII.I.A-405a**	~~3.3-1, 114~~**3.3-1, 132**	~~A~~**E**
Nozzle	Spray	Copper alloy >15% Zn	Air – outdoor (ext)	~~None~~**Cracking**	~~None~~**External Surfaces Monitoring of Mechanical Components**	~~VII.J.AP-144~~**VII.I.A-405a**	~~3.3-1, 114~~**3.3-1, 132**	A
Nozzle	Spray	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	~~None~~**Cracking**	~~None~~**External Surfaces Monitoring of Mechanical Components**	~~VII.J.AP-144~~**VII.I.A-405a**	~~3.3-1, 114~~**3.3-1, 132**	A

Table 3.3.2-15: Fire Protection – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	~~None~~Cracking	~~None~~External Surfaces Monitoring of Mechanical Components	~~VII.J.AP-144~~VII.I.A-405a	~~3.3-1, 114~~3.3-1, 132	A
Tubing	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (int)	~~None~~Cracking	~~None~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	~~VII.J.AP-144~~VII.I.A-405a	~~3.3-1, 114~~3.3-1, 132	~~A~~E
Tubing	Pressure boundary	Copper alloy >15% Zn	Air – outdoor (ext)	~~None~~Cracking	~~None~~External Surfaces Monitoring of Mechanical Components	~~VII.J.AP-144~~VII.I.A-405a	~~3.3-1, 114~~3.3-1, 132	A
Tubing	Pressure boundary	Copper alloy >15% Zn	Air – outdoor (int)	~~None~~Cracking	~~None~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	~~VII.J.AP-144~~VII.I.A-405a	~~3.3-1, 114~~3.3-1, 132	~~A~~E
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	~~None~~Cracking	~~None~~External Surfaces Monitoring of Mechanical Components	~~VII.J.AP-144~~VII.I.A-405a	~~3.3-1, 114~~3.3-1, 132	A

Table 3.3.2-15: Fire Protection – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (int)	~~None~~**Cracking**	~~None~~**Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	~~VII.J.AP-144~~**VII.I.A-405a**	~~3.3-1, 114~~**3.3-1, 132**	~~A~~**E**
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – outdoor (ext)	~~None~~**Cracking**	~~None~~**External Surfaces Monitoring of Mechanical Components**	~~VII.J.AP-144~~**VII.I.A-405a**	~~3.3-1, 114~~**3.3-1, 132**	A
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – outdoor (int)	~~None~~**Cracking**	~~None~~**Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	~~VII.J.AP-144~~**VII.I.A-405a**	~~3.3-1, 114~~**3.3-1, 132**	~~A~~**E**

Revise SLRA Table 3.3.2-16 as follows:

Table 3.3.2-16: Emergency Diesel Generator Cooling Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	~~None~~Cracking	~~None~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	~~VII.J.AP-144~~VII.I.A-405a	~~3.3-1, 114~~3.3-1, 132	~~C~~E
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Air – outdoor (ext)	~~None~~Cracking	~~None~~Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	~~VII.J.AP-144~~VII.I.A-405a	~~3.3-1, 114~~3.3-1, 132	~~C~~E
Sight glass	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	~~None~~Cracking	~~None~~External Surfaces Monitoring of Mechanical Components	~~VII.J.AP-144~~VII.I.A-405a	~~3.3-1, 114~~3.3-1, 132	A
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – indoor uncontrolled (ext)	~~None~~Cracking	~~None~~External Surfaces Monitoring of Mechanical Components	~~VII.J.AP-144~~VII.I.A-405a	~~3.3-1, 114~~3.3-1, 132	A

Revise the SLRA Notes for Table 3.3.2-16 as follows:

Notes for Table 3.3.2-16

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

D. Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

E. Consistent with NUREG-2191 material, environment, and aging effect but a different AMP is credited or NUREG-2191 identifies a plant-specific AMP.

Revise SLRA Table 3.4-1 Item 106 as follows:

Table 3.4-1: Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.4-1, 106	Copper alloy (>15% Zn or >8% Al) piping, piping components exposed to air, condensation	Cracking due to SCC	AMP XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	~~Not used. Cracking of copper alloys depends on the presence of ammonia or ammonia compound. A review of Turkey Point OE confirms that neither ammonia nor ammonia compounds are present~~ **Consistent with NUREG-2191. The External Surfaces Monitoring of Mechanical Components AMP will be used to manage cracking of copper alloy >15% Zn or >8% Al piping, piping components exposed to air, condensation.**

Revise SLRA Table 3.4.2-1 as follows:

Table 3.4.2-1: Main Steam and Turbine Generators – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Tubing	Pressure boundary	Copper alloy >15% Zn	Air – outdoor (ext)	~~None~~**Cracking**	~~None~~**External Surfaces Monitoring of Mechanical Components**	~~VIII.I.SP-6~~**VIII.H.S-454**	~~3.4-1, 054~~**3.4-1, 106**	A
Valve body	Pressure boundary	Copper alloy >15% Zn	Air – outdoor (ext)	~~None~~**Cracking**	~~None~~**External Surfaces Monitoring of Mechanical Components**	~~VIII.I.SP-6~~**VIII.H.S-454**	~~3.4-1, 054~~**3.4-1, 106**	A

Associated Enclosures:

None

NRC RAI Letter No. ML18218A199 Dated August 6, 2018

RAI 3.3.2.2.9-1

Background:

SLRA Section 3.3.2.2.9 states:

> The stainless steel components are above groundwater and, therefore, do not require management as detailed above. A review of OE [operating experience] for Turkey Point indicates there are occurrences of concrete degradation that could lead to the penetration of water to the metal surface; therefore, a loss of material due to general, pitting, and crevice corrosion of steel piping and tanks exposed to concrete is an aging effect that requires management.
>
> Consistent with the recommendation of GALL-SLR, the Buried and Underground Piping and Tanks AMP is used to manage loss of material in steel piping exposed to concrete. This AMP provides for the management of aging effects through periodic visual inspection. Any visual evidence of loss of material will be evaluated for acceptability.

SLRA Table 3.3-1, AMR item 3.3.1-202 states, "[c]onsistent with NUREG-2191. A review of Turkey Point OE [operating experience] confirms no degradation of concrete that would allow exposure of embedded portions of stainless steel piping or piping components to groundwater; there are no aging effects to manage."

SLRA Table 3.3-1, AMR item 3.3.1-112 states that it is not used. It also states, "[a] review of OE [operating experience] for Turkey Point indicates there are occurrences of concrete degradation that could lead to the penetration of water to the metal surface; therefore, a loss of material due to general, pitting, and crevice corrosion of steel piping and tanks exposed to concrete is an aging effect that requires management."

Issue:

Depending on where the stainless steel components are located, rainwater could penetrate degraded concrete and come in contact with the stainless steel components as it proceeds through the soil to the water table.

The statements in SLRA Section 3.3.2.2.9, SLRA Table 3.3-1, AMR item 3.3.1-112, and SLRA Table 3.3-1, AMR item 3.3.1-202 are inconsistent in regard to the review of plant-specific operating experience associated with degraded concrete.

SLRA Table 3.3-1, AMR item 3.3.1-112 states that it is not used and SLRA Section 3.3.2.2.9 states that the Buried and Underground Piping and Tanks AMP will be used to manage loss of material in steel piping exposed to concrete. However, a review of the SLRA Table 2s associated with SLRA Section 3.3, reveals that there are no carbon steel AMR items exposed to concrete. It is unclear how loss of material steel components exposed to concrete will be managed by the Buried and Underground

Piping and Tanks program when there are no corresponding Table 2 items.

Request:

1. Describe the location of the stainless steel components embedded in concrete (e.g., inside a building). State whether the concrete surrounding the stainless steel components is susceptible to penetration by rainwater as it proceeds through the soil to the water table.
2. Clarify the inconsistency between SLRA Section 3.3.2.2.9 and SLRA Table 3.3-1, AMR item 3.3.1-112, regarding plant-specific operating experience associated with degraded concrete. If the basis of the statements is that there are instances of plant-specific operating experience revealing that concrete degradation has occurred in the vicinity of carbon steel embedded in concrete but not stainless steel embedded in concrete, state the basis of why concrete degradation will not occur in the future for stainless steel components embedded in concrete.
3. State which AMR items will be used to manage loss of material for steel piping exposed to concrete.

FPL Response:

1. Stainless steel is embedded in concrete in three systems; Safety Injection, Residual Heat Removal, and Waste Disposal. All stainless steel components embedded in concrete are in the auxiliary building. The concrete surrounding the stainless steel piping in the Waste Disposal system is not potentially susceptible to penetration by rainwater as the piping is not embedded in the slab, all drains are gravity fed to the waste disposal tank and any waste collection below the waste disposal tank is collected through sump pumps. The concrete surrounding the stainless steel piping in the Safety Injection and Residual Heat Removal systems is not potentially susceptible to penetration by rainwater as it proceeds through the soil to the water table. The Safety Injection and Residual Heat Removal piping penetrates the exterior of the building through a trench and is not exposed to soil. On the exterior of the building, loss of material and cracking of the pipe is managed by the Buried and Underground Piping and Tanks AMP. On the interior of the building loss of material and cracking of the pipe is managed by the External Surfaces Monitoring of Mechanical Components AMP. In review of the SLRA related to this RAI, inconsistencies were found with respect to auxiliary systems line items for stainless steel in concrete. The inconsistent line items are updated to show there are no instances of stainless steel piping exposed to concrete in the presence of groundwater. These changes are shown in the Associated SLRA Revisions section below.
2. The statements in SLRA Section 3.3.2.2.9 and AMR item 3.3-1, 112 are in agreement with respect to plant specific operating experience and concrete degradation. There are no stainless steel components in concrete potentially in contact with groundwater as stated in SLRA Section 3.3.2.2.9. Per RAI 3.1.2.2.15-1, SLRA Section 3.3.2.2.9 has been revised as shown in the Associated SLRA

Revisions section of RAI 3.1.2.2.15-1 to state this more clearly.

3. Steel piping components exposed to concrete, i.e. the gray cast iron drains from Table 3.3.2-8, are managed by the Buried and Underground Piping and Tanks AMP per AMR item 3.3-1, 109.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Table 3.3-1 and Table 3.3.2-8 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font). See RAI 3.1.2.2.15-1 for revisions to SLRA Section 3.2.2.9.

Revise SLRA Table 3.3-1 as follows:

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 107	Stainless steel, nickel alloy piping, piping components exposed to soil, concrete	Loss of material due to pitting, crevice corrosion, MIC (soil only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-2191. The Buried and Underground Piping and Tanks AMP is used to manage loss of material in stainless steel piping exposed to soil~~ and concrete~~.
3.3-1, 144	Stainless steel, steel, aluminum piping, piping components, tanks exposed to soil, concrete	Cracking due to SCC (steel in carbonate/bicarbonate environment only)	AMP XI.M41, "Buried and Underground Piping and Tanks"	No	~~Consistent with NUREG-2191. The Buried and Underground Piping and Tanks AMP is used to manage cracking in stainless steel piping exposed to concrete.~~**Not used. Per Further Evaluation 3.3.2.2.9 SCC is not applicable aging effect for steel or stainless steel exposed to concrete. Steel and stainless steel exposed to soil are managed using other line items.**

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect / Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 202	Stainless steel piping, piping components exposed to concrete	None	None	Yes (SRP-SLR Section 3.3.2.2.9)	Consistent with NUREG-2191. A review of Turkey Point OE confirms ~~no~~ degradation of concrete that would allow exposure of embedded portions of stainless steel piping or piping components togroundwater~~;~~**. However, there are no piping components embedded in concrete in the areas which would allow groundwater to penetrate. As such,** there are no aging effects to manage. Further evaluation is documented in Section 3.3.2.2.9.

Revise SLRA Table 3.3.2-8 as follows:

Table 3.3.2-8: Waste Disposal – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Piping	Leakage Boundary (Spatial)	Stainless steel	Concrete	~~Cracking~~ **None**	~~Buried and Underground Piping and Tanks~~**None**	~~VII.I.A-425~~**VII.J.AP-19**	3.3-1, 202	A
~~Piping~~	~~Leakage Boundary (Spatial)~~	~~Stainless steel~~	~~Concrete~~	~~Loss of material~~	~~Buried and Underground Piping and Tanks~~	~~VII.I.AP-137~~	~~3.3-1, 107~~	~~A~~

Table 3.3.2-8: Waste Disposal – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Piping	Pressure boundary	Stainless steel	Concrete	~~Cracking~~ None	~~Buried and Underground Piping and Tanks~~None	~~VII.I.A-425~~VII.J.AP-19	3.3-1, 202	A
~~Piping~~	~~Pressure boundary~~	~~Stainless steel~~	~~Concrete~~	~~Loss of material~~	~~Buried and Underground Piping and Tanks~~	~~VII.I.AP-137~~	~~3.3-1, 107~~	~~A~~
Piping and piping components	Structural Integrity (Attached)	Stainless steel	Concrete	~~Cracking~~ None	~~Buried and Underground Piping and Tanks~~None	~~VII.I.A-425~~VII.J.AP-19	3.3-1, 202	A
~~Piping and piping components~~	~~Structural Integrity (Attached)~~	~~Stainless steel~~	~~Concrete~~	~~Loss of material~~	~~Buried and Underground Piping and Tanks~~	~~VII.I.AP-137~~	~~3.3-1, 107~~	~~A~~

Associated Enclosures:

None

NRC RAI Letter No. ML18218A199 Dated August 6, 2018

2. SS Nickel Alloy Aluminum Alloy Further Evaluations

Regulatory Basis:

Section 54.21(a)(3) of 10 CFR requires an applicant to demonstrate that the effects of aging for structures and components will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. One of the findings that the staff must make to issue a renewed license (10 CFR § 54.29(a)) is that actions have been identified and have been or will be taken with respect to the managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under § 54.21, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis (CLB). As described in SRP-LR, an applicant may demonstrate compliance with 10 CFR 54.21(a)(3) by referencing the GALL Report. In order to complete its review and enable making a finding under 10 CFR § 54.29(a), the staff requires additional information in regard to the matters described below.

RAI 3.2.2.2.2-1

Background:

Table 3.2.2.2.2-1, below, is a compilation of several SLRA Table 2 entries including the SLRA Table 2 number, system, component type, intended function, material, environment, aging effect requiring management (AERM), SLRA aging management program (AMP), and SLRA Table 1 number.

Issue:

For the SLRA Table 2 entries in the Table 3.2.2.2.2-1, below, the staff lacks sufficient information to conclude that the cited AMP will be capable of detecting aging effects as follows. For the:

1. Heat exchanger internals (SLRA Table 3.3.2-9), the extent of accessible internal surfaces of the heat exchanger available for inspection is not known.
2. Heat exchanger fins (SLRA Tables 3.3.2-12, 3.3.2-14, and 3.3.2-16), it is not clear how the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components will be effective at detecting loss of material and cracking in the heat exchanger fins exposed to an external air environment unless the heat exchanger is located within ducting.
3. Heat exchanger head/tubesheet (SLRA Table 3.2.2-6) and heat exchanger tubesheet (SLRA Table 3.2.2-5), it is not clear whether the internal side of the tubes are exposed to the air-indoor uncontrolled environment and treated water/treated borated water/treated borated water greater than 140 degrees is on

the shell side of the heat exchanger tubes or vice versa. If the shell side of the tubes are exposed to the air-indoor uncontrolled environment, it is not clear how the External Surfaces Monitoring of Mechanical Components program will be effective at detecting loss of material and cracking.

4. Heat exchanger housing (SLRA Table 3.3.2-16), the extent of accessible internal surfaces of the heat exchanger available for inspection is not known.
5. Heat exchanger tubes (SLRA Tables 3.3.2-10 and 3.3.2-11), it is not clear how the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program: (a) will detect cracking or loss of material on the external surfaces of the tubes unless the heat exchanger is located within ducting, and (b) will detect aging effects on heat exchanger tubes within the tube bundle and for those surfaces of the outer tubes that are not directly exposed to view. SLRA Section B.2.3.25, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," states that the program will use visual inspections and when appropriate, surface examinations. Absent inspection techniques such as eddy current, the staff is not aware of visual or surface examination techniques that will detect loss of material or cracking (to anything more than a limited extent) in heat exchanger tubes.
6. Strainer element (SLRA Table 3.2.2-5), it is not clear how the External Surfaces Monitoring of Mechanical Components program will detect loss of material and cracking on strainer elements versus the strainer body.

Request:

1. State the extent of the internal surfaces of the heat exchanger that will be accessible for internal inspections and the basis for why the extent of inspections will be adequate to detect cracking and loss of material for stainless steel heat exchangers exposed to outdoor air (internal).
2. State the basis for why the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is adequate to detect aging effects on the external surfaces of the heat exchanger fins.
3. Clarify the configuration of the heat exchangers (i.e., state which fluid flows through the internal side of the tube and the shell side of the tube). If the shell side of the tubes are exposed to the air-indoor uncontrolled environment, state how the External Surfaces Monitoring of Mechanical Components will be effective at detecting loss of material and cracking on the heat exchanger head and tube sheet.
4. State the extent of the internal surfaces of the heat exchanger housing that will be accessible for internal inspections and the basis for why the extent of inspections will be adequate to detect cracking and loss of material of stainless steel heat exchanger housings exposed to outdoor air (internal).

5. State what inspection techniques will be used to detect loss of material and cracking in the heat exchanger tubes and the basis for the effectiveness of the technique when heat exchanger tubes are inspected as part of the representative sample.
6. State the basis for why the External Surfaces Monitoring of Mechanical Components program is adequate to detect aging effects on the external surfaces of the strainer elements.

Table 3.2.2.2.2-1

SLRA Table 2	System	Component Type	Intended Function	Material	Environment	AERM	SLRA AMP	LRA Table 1
3.3.2-9	Plant Air	Heat exchanger	Pressure boundary	Stainless steel	Air – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 004
3.3.2-12	Control Building Ventilation	Heat exchanger (fins)	Heat transfer	Aluminum	Air – indoor controlled (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 242
3.3.2-14	Turbine Building Ventilation	Heat exchanger (fins)	Heat transfer	Aluminum	Air – indoor controlled (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 242
3.3.2-16	Emergency Diesel Generator Cooling Water	Heat exchanger (fins)	Heat transfer	Aluminum	Air – outdoor (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 242
3.3.2-12	Control Building Ventilation	Heat exchanger (fins)	Heat transfer	Aluminum	Air – indoor controlled (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 254
3.3.2-14	Turbine Building Ventilation	Heat exchanger (fins)	Heat transfer	Aluminum	Air – indoor controlled (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 254
3.3.2-16	Emergency Diesel Generator Cooling Water	Heat exchanger (fins)	Heat transfer	Aluminum	Air – outdoor (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 254

Table 3.2.2.2.2-1

SLRA Table 2	System	Component Type	Intended Function	Material	Environment	AERM	SLRA AMP	LRA Table 1
3.2.2-6	Containment Post Accident Monitoring and Control	Heat exchanger (head/ tubesheet)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	3.2-1, 004
3.2.2-6	Containment Post Accident Monitoring and Control	Heat exchanger (head/ tubesheet)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	3.2-1, 007
3.3.2-16	Emergency Diesel Generator Cooling Water	Heat exchanger (housing)	Pressure boundary	Stainless steel	Air – outdoor (int)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 004
3.3.2-16	Emergency Diesel Generator Cooling Water	Heat exchanger (housing)	Pressure boundary	Stainless steel	Air – outdoor (int)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 006
3.3.2-11	Auxiliary Building and Electrical Equipment Room Ventilation	Heat exchanger (tubes)	Leakage Boundary (Spatial)	Stainless steel	Condensation (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 004
3.3.2-10	Normal Containment Ventilation	Heat exchanger (tubes)	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 004

Table 3.2.2.2.2-1

SLRA Table 2	System	Component Type	Intended Function	Material	Environment	AERM	SLRA AMP	LRA Table 1
3.3.2-11	Auxiliary Building and Electrical Equipment Room Ventilation	Heat exchanger (tubes)	Leakage Boundary (Spatial)	Stainless steel	Condensation (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 241
3.3.2-10	Normal Containment Ventilation	Heat exchanger (tubes)	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	3.3-1, 241
3.2.2-5	Residual Heat Removal	Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	3.2-1, 004
3.2.2-5	Residual Heat Removal	Heat exchanger (tubesheet)	Pressure boundary	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	3.2-1, 007
3.2.2-5	Residual Heat Removal	Strainer element	Filter	Stainless steel	Air – indoor uncontrolled (ext)	Loss of material	External Surfaces Monitoring of Mechanical Components	3.2-1, 004
3.2.2-5	Residual Heat Removal	Strainer element	Filter	Stainless steel	Air – indoor uncontrolled (ext)	Cracking	External Surfaces Monitoring of Mechanical Components	3.2-1, 007

FPL Response:

1. The heat exchanger, summarized in SLRA Table 3.3.2-9 and referred to in items 3.3-1, 004 and 3.3-1, 006, is an air to air aftercooler with a radiator type heat exchanger. It is exposed to compressed air inside the tubes and ambient outdoor air outside the tubes. The internal surfaces of the heat exchanger are not normally accessible for inspection. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP described in SLRA Section B.2.3.25 is a representative sampling program. The aftercooler heat exchanger tubes are a component within the population of stainless steel components exposed to outdoor air. The condition of the heat exchanger may be assessed based on inspection of other components with the same material and environment, such as the stainless steel piping downstream of the heat exchanger. The heat exchanger tubes may be made available for inspection if required based on the results of the representative components within the material-environment population.
2. Aluminum heat exchanger fins in the Control Building Ventilation (SLRA Table 3.3.2-12), and Turbine Building Ventilation (SLRA Table 3.3.2-14) exposed to air – indoor controlled are inside air handling units. The heat exchanger fins exposed to air-outdoor (SLRA Table 3.3.2-12) are internal to the emergency diesel generator turbocharger aftercoolers. While external surfaces are being examined, they are internal to larger components and will require maintenance activities to present an opportunistic inspection. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP, as described in SLRA B.2.3.25 and consistent with NUREG-2191 XI.M38, is used to detect loss of material and cracking on the fins. The AMP is applicable to heat exchanger components and uses ASME Section XI VT-1 inspections as well as surface examinations to detect cracking and loss of material. As the components and relevant aging effects are within the scope of the AMP, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP, as described in SLRA B.2.3.25 and consistent with NUREG-2191 XI.M38, will be adequate to manage the components.
3. The heat exchanger (head/tubesheet) in SLRA Table 3.2.2-6 refers to the post accident sample system sample cooler. The head and tubesheet edge are exposed to containment air on the exterior of the heat exchanger only. The interior of the head, tube side of the tubesheet, and the interior of the tubes are exposed to treated borated water. The exterior of the tubes, shell side of the tubesheet, and the interior of the shell are exposed to closed cycle cooling water (treated water). The External Surfaces Monitoring of Mechanical Components AMP, as described in SLRA B.2.3.23 and consistent with NUREG-2191, XI.M36, is used to manage the aging effects on the exterior of the heat exchanger freely exposed to the containment atmosphere. Additionally, SLRA Table 3.2.2-6 now recognizes treated borated water as an internal environment for the heat exchanger (head/tubesheet) as it was not previously included. The associated aging effects and AMP are shown in the SLRA revision below.

The heat exchangers listed in SLRA Table 3.2.2-5 are the residual heat removal heat exchangers and the pump seal heat exchangers. These heat exchangers are of similar construction and each consist of a carbon steel shell exposed to Air-indoor uncontrolled on the exterior and treated water on the interior. The heat exchanger tubes are exposed to treated water on the exterior and treated borated water on the interior. The tubesheet is exposed to treated water on the shell side and treated borated water on the channel head side. The tubesheet is bolted between the shell and channel head and is exposed to air-indoor uncontrolled around the exterior (edge). The channel head is exposed to treated borated water on the interior and air-indoor uncontrolled on the exterior. The External Surfaces Monitoring of Mechanical Components AMP, as described in SLRA B.2.3.23 and consistent with NUREG-2191, XI.M36, is used to manage the aging effects on the exterior of the heat exchanger, including the edge of the tubesheet, freely exposed to the containment atmosphere.

4. The heat exchanger housings in SLRA Table 3.3.2-16 are the emergency diesel generator turbocharger aftercoolers. The internal surfaces of the aftercooler are not normally accessible for inspection. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP described in SLRA Section B.2.3.25 is a representative sampling program. The aftercooler heat exchanger tubes are a component within the sampling population of stainless steel components exposed to outdoor air. The condition of the aftercooler may be assessed based on inspection of other components with the same material and environment. The aftercooler tubes may be made available for inspection if required based on the results of the representative components within the material-environment population. The air intake of each diesel generator can be disassembled to inspect the aftercooler housing if required.

5. The heat exchanger tubes in SLRA Table 3.3.2-10 and 3.3.2-11 are the normal containment coolers and the auxiliary building and electrical equipment room ventilation coolers in air handling units. Some of the normal containment coolers have copper alloy greater than 15% zinc tubes as described in SLRA Table 3.3.2-10. In addition to the heat exchanger components identified in Table 3.2.2.2.2-1, copper alloy with >15% zinc heat exchanger tubes are now managed for cracking per the response to RAI 3.3.2.1.4-1.

   Heat exchanger tubes are a part of the defined scope of NUREG-2191 aging management program XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components". Per the first sentence of the first element, "This program includes the internal surfaces of piping, piping components, ducting, heat exchanger components, and other components." Per element 4 of NUREG 2191 XI.M38, Detection of Aging Effects, visual inspections or surface examinations are conducted to manage cracking every 10 years during the SPEO. Surface examinations are performed to plant specific procedures, if visual inspections are performed they will be done per ASME Section XI VT-1 examinations.

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP described in SLRA Section B.2.3.25 is a representative sampling program. Heat exchanger tubes are a component within a population of all components made of the same material and exposed to the same environment. The representative sample consists of 20 percent of the sampling population, up to 25 components. The condition of the heat exchanger may be assessed based on inspection of other representative components with the same material and environment which are more accessible. An inspection of 20% of the surface area of a component is required for it to qualify as a part of the representative sample.

The population for copper alloy greater than 15% zinc components exposed to condensation on their external surface is exclusively heat exchanger tubes. There is no opportunity for inspection of other representative components which are more accessible. However, the heat exchanger tubes are located in air handling units and are accessible for inspection when the coolers are opened for surveillance or maintenance. Additionally, as they are air handler heat exchangers, the tubes are generally not concealed in a tube bundle to an extent that would prevent inspection of 20 percent of the surface area. The other copper alloy >15% heat exchanger tubes are emergency diesel generator radiators which would not be a part of the representative sample as the tubes are not accessible for inspection. However, there are other copper alloy greater than 15% zinc components in the same material-environment population that are accessible for inspection and representative of components with the same material and environment.

6. The strainer element in question is the containment sump strainer module. The strainer body is an open structural support system which leaves the strainer elements fully exposed to the containment environment. As described in SLRA Table 3.2.2-5, the strainer elements are constructed of stainless steel and exposed to air – indoor uncontrolled. The External Surface Monitoring of Mechanical Components AMP described in SLRA Section B.2.3.25 is a representative sampling program. As such, consistent with NUREGs-2191 XI.M36, and as described in SLRA B.2.3.23, the External Surface Monitoring of Mechanical Components inspection of other components in the same material and environment is representative of the condition of the strainer element. In the event the strainer elements are unbolted and lifted as a part of routine maintenance, the surface of the component is available for inspection and may be inspected as a part of the populations representative sample. As the environment the strainer filter elements are exposed to is freely mixed with the containment environment, the External Surfaces of Mechanical Components AMP is used to manage the aging effects.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Table 3.2.2-6 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Table 3.2.2-6: Containment Post Accident Monitoring and Control – Summary of Aging Management Evaluation								
Heat Exchanger (~~head/~~ tubesheet)	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Closed Treated Water Systems	V.D1.EP-93	3.2-1, 031	B
Heat exchanger (head/ tubesheet)	Pressure boundary	Stainless steel	Treated borated water (int)	Loss of material	Water Chemistry One-Time Inspection	V.D1.EP-41	3.2-1, 022	A

Associated Enclosures:

None

NRC RAI Letter No. ML18218A199 Dated August 6, 2018

RAI 3.3.2.2.3-1

Background:

SLRA Table 3.3-1, items 3.3.1-146 and 3.3.1-246 states that, "[t]he stainless steel underground piping in the Auxiliary Systems is managed using other line items."

Issue:

Based on a search of the SLRA auxiliary system Table 2s, there are no stainless steel piping or piping components exposed to an underground environment. It is not clear to the staff whether there are missing stainless steel items in the auxiliary system Table 2s, or the statement associated with items 3.3.1-146 and 3.3.1-246 is in error.

Request:

State whether the statement associated with items 3.3.1-146 and 3.3.1-246 is in error or identify the AMR items that are missing from the auxiliary system Table 2s.

FPL Response:

The statements in SLRA Table 3.3-1 associated with items 3.3-1, 146 and 3.3-1, 246 are in error. There are no stainless steel or nickel alloy components exposed to an underground environment in the auxiliary systems. The revised Table 3.3-1 is shown in the Associated SLRA Revisions below.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Table 3.3-1 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 146	Stainless steel underground piping, piping components, tanks	Cracking due to SCC	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/Linings for InScope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.3)	Not used. ~~The stainless steel underground piping in the Auxiliary Systems is managed using other line items.~~ **There are no stainless steel underground piping, piping components or tanks in the Auxiliary Systems.**
3.3-1, 246	Stainless steel, nickel alloy underground piping, piping components, tanks	Loss of material due to pitting, crevice corrosion	AMP XI.M32, "One-Time Inspection," AMP XI.M41, "Buried and Underground Piping and Tanks," or AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	Yes (SRP-SLR Section 3.3.2.2.4)	Not used. ~~The stainless steel underground piping in the Auxiliary Systems is managed using other line items.~~ There are no underground **stainless steel or** nickel alloy piping, piping, components, or tanks in the Auxiliary Systems.

Associated Enclosures:

None

NRC RAI Letter No. ML18218A199 Dated August 6, 2018

3. Internal Coatings / Lining

Regulatory Basis:

Section 54.21(a)(3) of 10 CFR requires an applicant to demonstrate that the effects of aging for structures and components will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. One of the findings that the staff must make to issue a renewed license (10 CFR § 54.29(a)) is that actions have been identified and have been or will be taken with respect to the managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under § 54.21, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis (CLB). As described in SRP-LR, an applicant may demonstrate compliance with 10 CFR 54.21(a)(3) by referencing the GALL Report. In order to complete its review and enable making a finding under 10 CFR § 54.29(a), the staff requires additional information in regard to the matters described below.

RAI B.2.3.29-1

Background:

SLRA Section B.2.3.29 states that in regard to:

1. The scope of the program:

    This AMP is a condition monitoring program that manages degradation of internal coatings/linings exposed to raw water, treated water, treated borated water, waste water, lubricating oil or fuel oil that can lead to loss of material of base materials <u>and</u> downstream effects such as reduction in flow, reduction in pressure or reduction of heat transfer when coatings/linings become debris.

2. The detection of aging effects, "[f]or cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces."
3. Acceptance criteria, "[a]ctive peeling and delamination are not acceptable." It also states, "[t]here are no active and/or significant indications of peeling or delamination."

SLRA Section 17.2.22.9 states:

4. Similarly to item 1, above, the UFSAR uses the term "<u>and</u>" in lieu of "or" when stating the scope of the program associated with terms of the potential aging effects.
5. Similarly to item 3, above, the UFSAR uses the term "active" to describe acceptance criteria in relation to peeling and delamination.

Issue:

1. The scope of the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program is not consistent with the "scope of program" program element of AMP XI.M42 because the term "and" implies that both the component's intended function and a downstream component's intended function must be impacted by loss of coating integrity for the coating to be within the scope of the program. AMP XI.M42 recommends that the criteria for inclusion are either of the impacts.
2. GALL-SLR Report AMP XI.M42 recommends that, "[f]or cementitious coatings/linings inspectors should have a minimum of 5 years of experience inspecting or testing concrete structures or cementitious coatings/linings or a degree in the civil/structural discipline and a minimum of 1 year of experience."
3. The acceptance criteria for GALL-SLR Report AMP XI.M42 recommends that, "[t]here are no indications of peeling or delamination."
4. GALL-SLR Report Table XI-01, "FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs," recommends that the term "or" is used when describing aging effects associated with the program (i.e., "loss of material of base materials or downstream effects such as...").
5. GALL-SLR Report Table XI-01, recommends that any indications of peeling or delamination are not acceptable.

Request:

1. State the basis for using the term "and."
2. State the basis for why the statement in SLRA Section B.2.3.29 regarding cementitious coating inspector qualifications is consistent with GALL-SLR AMP XI.M42.
3. State the basis for why allowing degraded coatings that do not exhibit active or significant indications of peeling or delamination is consistent with GALL-SLR AMP XI.M42.
4. State the basis for why SLRA Section 17.2.2.29 states "and" instead of "or" when stating the scope of the program associated with terms of the potential aging effects.
5. State the basis for why SLRA Section 17.2.2.29 uses the term "active" in relation to acceptance criteria for peeling or delamination.

FPL Response:

1. Internal coatings/linings that affect either the component's intended function or the component's downstream intended function are within the scope of the program. SLRA Section B.2.3.29 is revised to remove "and" and replace with "or." This change is shown in the Associated SLRA Revisions section below.
2. The following statement is added to SLRA Section B.2.3.29 Paragraph 3 to clarify that the AMP is consistent with GALL-SLR AMP XI.M42: "For cementitious coatings/linings, inspectors 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." This change is shown in the Associated SLRA Revisions section below.
3. Any indications of coating peeling or delamination are not acceptable. SLRA Section B.2.3.29 is revised to remove the "significant" and "active" qualifiers associated with the peeling or delamination acceptance criteria. This change is shown in the Associated SLRA Revisions section below. As described in the AMP basis document, the degraded coatings will either be repaired, replaced, removed or evaluated and returned to service if (a) physical testing is conducted to ensure that the remaining coating is tightly bonded to the base metal; (b) the potential for further degradation of the coating is minimized, (i.e., any loose coating is removed, the edge of the remaining coating is feathered); (c) adhesion testing using ASTM International standards endorsed in RG 1.54 (e.g., pull-off testing, knife adhesion testing) is conducted at a minimum of three sample points adjacent to the defective area; (d) an evaluation is conducted of the potential impact on the system, including degraded performance of downstream components due to flow blockage and loss of material or cracking of the coated component; and (e) follow-up visual inspections of the degraded coating are conducted within two years from detection of the degraded condition, with an additional inspection within two years, or until the degraded coating is repaired or replaced.
4. Internal coatings/linings that affect either the component's intended function or the component's downstream intended function are within the scope of the program. SLRA Section 17.2.2.29 is revised to remove "and" and replace with "or". This change is shown in the Associated SLRA Revisions section below.
5. Any indications of coating peeling or delamination are not acceptable and will be entered into the corrective action program for evaluation and disposition. SLRA Section 17.2.2.29 is revised to remove the "active" qualifier associated with the peeling or delamination acceptance criteria. This change is shown in the Associated SLRA Revisions section below.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Sections 17.2.2.29 and B.2.3.29 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Revise SLRA Section 17.2.2.29 paragraph 1 sentence 2 as follows:

> This AMP is a condition monitoring program that manages degradation of internal coatings/linings exposed to raw water, treated water, treated borated water, waste water, lubricating oil or fuel oil that can lead to loss of material of base materials ~~and~~ **or** downstream effects such as reduction in flow, reduction in pressure or reduction of heat transfer when coatings/linings become debris.

Revise SLRA Section 17.2.2.29 paragraph 4 as follows:

> ~~Active peeling~~ **Peeling** and delamination are not acceptable. Blisters are not acceptable unless a coating specialist has determined them to be surrounded by sound material with size and frequency not increasing. Minor cracks in cementitious coatings are acceptable provided there is no evidence of debonding. All other degraded conditions are evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in NRC RG 1.54. For coated/lined surfaces determined to not meet the acceptance criteria, physical testing is performed where physically possible (i.e., sufficient room to conduct testing) in conjunction with repair or replacement of the coating/lining.

Revise SLRA Section B.2.3.29 paragraph 1 sentence 2 and paragraph 2 sentence 1 as follows:

> This AMP is a condition monitoring program that manages degradation of internal coatings/linings exposed to raw water, treated water, treated borated water, waste water, lubricating oil or fuel oil that can lead to loss of material of base materials ~~and~~ **or** downstream effects such as reduction in flow, reduction in pressure or reduction of heat transfer when coatings/linings become debris.
>
> ~~This AMP is a condition monitoring program that manages degradation of internal coatings/linings exposed to raw water, treated water, treated borated water, waste water, lubricating oil or fuel oil that can lead to loss of material of base materials and downstream effects such as reduction in flow, reduction in pressure or reduction of heat transfer when coatings/linings become debris.~~

Revise SLRA Section B.2.3.29 paragraph 2 item a. as follows:

> a. There are no ~~active and/or significant~~ indications of peeling or delamination.

Revise SLRA Section B.2.3.29 paragraph 3 as follows:

> For tanks and heat exchangers, accessible surfaces are inspected. Piping inspections are sampling-based. The training and qualification of individuals involved in coating/lining inspections of non-cementitious coatings/linings are conducted in accordance with ASTM International Standards endorsed in NRC RG 1.54. The

training and qualification of those individuals also includes guidance from the staff associated with the standards endorsed in RG 1.54. ~~For cementitious coatings, training and qualifications are based on an appropriate combination of education and experience related to inspecting concrete surfaces~~. **For cementitious coatings/linings, inspectors 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.** ~~Active peeling~~ Peeling and delamination are not acceptable. Blisters are evaluated by a coatings specialist with the blisters being surrounded by sound material and with the size and frequency not increasing. Minor cracks in cementitious coatings are acceptable provided there is no evidence of debonding. All other degraded conditions are evaluated by a coatings specialist. For coated/lined surfaces determined to not meet the acceptance criteria, the coating can be removed or physical testing is performed to determine where coating replacement or repair is required. This AMP is supplemented by inspections under the PTN Selective Leaching AMP (Section B.2.3.21), the PTN Open-Cycle Cooling Water System AMP (Section B.2.3.11), and the PTN Outdoor and Large Atmospheric Metallic Storage Tanks AMP (Section B.2.3.17).

Associated Enclosures:

None

NRC RAI Letter No. ML18218A199 Dated August 6, 2018

RAI B.2.3.29-2

Background:

During the audit, the staff reviewed the following plant-specific procedures:

- SPEC-C-004, "Engineering Maintenance Specification Form." This procedure states that coating inspectors can be qualified to NACE Level II, ANSI N18.1-1971, or possess equivalent knowledge as determined by a Nuclear Coatings Specialist.
- SPEC-M-086, "Specification Intake Cooling Water System Piping Inspections Turkey Point Units 3 and 4." This procedure states that: (a) the inspections of the internal coatings for piping in the intake circulating water system will be conducted every 72 months with an 18 month grace period; and (b) degraded rubber linings installed on valves requires an engineering evaluation. The specification does not have any provisions for additional inspections when inspection results do not meet acceptance criteria (e.g., cement lining debonding from the pipe).

Issue:

GALL-SLR AMP XI.M42 recommends that coatings inspectors be qualified in accordance with ASTM International standards endorsed in Regulatory Guide 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants," including staff limitations associated with a particular standard. It also recommends specific aspects of cementitious coating inspectors (e.g., experience, education). The staff is aware of the requirements for qualifying to NACE Level II and ANSI N18.1-1971. However, using the term, "possess equivalent knowledge as determined by a Nuclear Coatings Specialist," is not consistent with the GALL Report and lacks the detail the staff needs to evaluate this portion of the aging management program.

GALL-SLR AMP XI.M42 recommends that inspections occur at 6-year intervals if inspection results are acceptable and 4-year intervals if for example, peeling, delamination, blisters, or rusting are observed during inspections. The 72-month inspection interval is only consistent with the GALL-SLR Report AMP XI.M42 if degraded coatings as defined in the AMP are not detected. The 18 month grace period is not consistent with the GALL-SLR Report unless the multiple train provisions of GALL-SLR AMP XI.M42 are met.

GALL-SLR AMP XI.M42 recommends that indications such as cracking, flaking, and rusting are to be evaluated by a coatings specialist. Using engineering staff without this specific qualification is not consistent with GALL-SLR AMP XI.M42.

GALL-SLR AMP XI.M42 recommends a specific minimum threshold for additional inspections when inspection results do not meet acceptance criteria. The specification is not consistent with GALL-SLR AMP XI.M42 because it does not have any provisions

for additional inspections when inspection results do not meet acceptance criteria.

Request:

State the basis for:

1. Using a Nuclear Coatings Specialist to determine an appropriate level of qualification for coatings inspectors.
2. The periodicity of internal coating inspections for the intake cooling water coatings.
3. For using engineering staff to conduct evaluations of degraded coating conditions.
4. Not specifying a minimum set of additional inspections when degraded coatings that don't meet acceptance criteria are identified.

FPL Response:

1. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP implementing procedures will be clarified to state that the qualification requirements for coatings inspectors are consistent with the requirements of the ASTM standards referenced in Regulatory Guide 1.54. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is a new AMP so this action will be performed as part of implementation per SLRA commitment #33.
2. The enhancement to the Open Cycle Cooling Water System AMP and associated commitment #15 are revised such that the frequency for internal coatings inspections for the intake cooling water system may be reduced to every four years in accordance with NUREG-2191 Section XI.M42 Table XI.M42-1 pending coating inspection results. The 18 month grace period will be eliminated as part of SLRA implementation.
3. As stated in SLRA Section B.2.3.29, indications such as cracking, flaking, and rusting are to be evaluated by a coatings specialist. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP implementing procedures will be revised to reflect this program requirement. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is a new AMP so this action will be performed as part of implementation per SLRA commitment #33.
4. When degraded coatings that do not meet acceptance criteria are identified, additional inspections are performed in accordance with Element 7 Corrective Actions of NUREG-2191 AMP XI.M42. These additional inspections are identified in the AMP basis document. The implementing procedures will be revised to reflect this program requirement. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is a new AMP so this action will be performed as part of implementation per SLRA commitment #33. Section B.2.3.29 of

the SLRA is revised to state that the corrective action element for this new AMP is consistent with Element 7 Corrective Actions of NUREG-2191 AMP XI.M42.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Commitment #15, Section B.2.3.11, and Section B.2.3.29 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Revise the SLRA Section B.2.3.11 Enhancements table as follows:

Element Affected	Enhancement
3. Parameters Monitored or Inspected	The specific aging mechanism associated with coatings/linings (blistering, cracking, flaking, peeling, delamination, and rusting) and descriptions shall be delineated in the pertinent testing specification SPEC-M-086.
4. Detection of Aging Effects	The inspection interval for ICW piping internal inspections, as delineated in the pertinent testing specification SPEC-M-086, should not exceed five years. **Pending coating inspection results, specific locations may require coatings inspections every four years in accordance with NUREG-2191 Section XI.M42 Table XI.M42-1.** In addition, changes to piping internal inspection intervals are to be established by a coating specialist qualified in accordance with an ASTM International standard endorsed in NRC RG 1.54 (Reference B.3.20). For cementitious ICW piping coatings within the scope of the program, inspectors should 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.

Revise the SLRA Section B.2.3.29 paragraph 4 as follows:

The PTN Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP requires the creation of a new governing procedure in accordance with NUREG-2191, Section XI.M42 to monitor for and manage the aging effects associated with the internal surfaces of the in-scope miscellaneous piping, piping components, ducting, heat exchanger components, and other components. Pertinent existing specifications and procedures that supplement the governing procedure are also required to be updated to ensure that the inspection frequency and sampling criteria outlined in **Element 4 Detection of Aging Effects of NUREG-2191 AMP XI.M42** ~~NUREG-2191 Element 4~~ are followed and that all internal coatings are captured.

When degraded coatings that do not meet acceptance criteria are identified the corrective actions outlined in Element 7 Corrective Actions of NUREG-2191 AMP XI.M42 are followed.

Revise SLRA Commitment #15 as follows:

No.	Aging Management Program or Activity (Section)	NUREG-2191 Section	Commitment	Implementation Schedule
15	Open-Cycle Cooling Water System (17.2.2.11)	XI.M20	Continue the existing PTN Open-Cycle Cooling Water System AMP, including enhancement to: a) Delineate within the pertinent testing specification the descriptions of the specific aging mechanisms associated with coatings/linings (blistering, cracking, flaking, peeling, delamination, and rusting); b) Ensure that the inspection frequency for ICW piping internal inspections delineated in the pertinent testing specification should not exceed 5 years. <u>**Pending coating inspection results, specific locations may require coatings inspections every 4 years in accordance with NUREG-2191 Section XI.M42 Table XI.M42-1.**</u> In addition, changes to piping internal inspection intervals are to be established by a coating specialist qualified in accordance with an ASTM International standard endorsed in NRC RG 1.54. For cementitious ICW piping coatings within the scope of the program, inspectors should have a minimum of 5 years of experience inspecting or testing concrete structures or cementitious coatings/linings or a degree in the civil/structural discipline and a minimum of 1 year of experience. c) Ensure the pertinent testing specification coating acceptance criteria include the following: • There are no indications of peeling or delamination.	No later than 6 months prior to the SPEO, i.e.: PTN3: 1/19/2032 PTN4: 10/10/2032

Associated Enclosures:

None

NRC RAI Letter No. ML18218A199 Dated August 6, 2018

RAI B.2.3.29-3

Background:

During the audit, the staff reviewed plant-specific procedures 3-PMM-022.4 and 4-PMM-022.4, "Unit 3 (Unit 4) Diesel Fuel Oil Storage Tank Cleaning." These procedures are used in part to inspect internal coatings on the fuel oil storage tanks.

Issue:

Although the scope of program of the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program includes components exposed to fuel oil, there are no Table 2 AMR items for managing loss of coating integrity for components exposed to fuel oil. Based on a review of the Section 3.3 Table 2s, the Fuel Oil Chemistry and One-Time Inspection programs are the only programs cited for components exposed to fuel oil. In addition, based on the staff's review of the Fuel Oil Chemistry program, 3-PMM-022.4, and 4-PMM-022.4, there are not sufficient exceptions and enhancements to demonstrate consistency with GALL-SLR AMP XI.M42.

GALL-SLR AMP XI.M42 states that applicants may elect to manage loss of coating integrity with other programs (e.g., Fuel Oil Chemistry) as long as: (a) the recommendations of AMP XI.M42 are incorporated into the alternative program; (b) exceptions or enhancements associated with the recommendations in AMP XI.M42 are included in the alternative program; and (c) the FSAR supplement for AMP XI.M42 as shown in the GALL-SLR Report Table XI-01, "FSAR Supplement Summaries for GALL-SLR Report Chapter XI Aging Management Programs," is included in the application with a reference to the alternative AMP.

Request:

1. State the basis for why the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program and/or Fuel Oil Chemistry program are consistent with GALL-SLR Report AMP XI.M42 in regard to managing aging effects for internally coated components exposed to fuel oil.
2. State which AMR items will be used to manage loss of coating integrity for internally coated fuel oil components.

FPL Response:

1. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will manage loss of coating or lining integrity for the Unit 3 diesel fuel oil storage tank and the Unit 4 diesel fuel oil storage tank liners. This AMP is consistent with GALL-SLR AMP XI.M42. The Fuel Oil Chemistry AMP is used to manage loss of material for the Unit 3 diesel fuel oil storage tank and the Unit 4 diesel fuel oil storage tank liners. The Fuel Oil Chemistry AMP is consistent

with GALL-SLR AMP XI.M30 with an exception that is unrelated to the Unit 3 diesel fuel oil storage tank and the Unit 4 diesel fuel oil storage tank liners.

2. The SLRA is revised to include the necessary chapter 3 table item (VII.H1.A-416) for these fuel oil storage tanks. All accessible surfaces of these tanks will be inspected in accordance with SLRA Section B.2.3.29 which is consistent with GALL-SLR Report AMP XI.M42.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Section 3.3.2.1.18, Section 3.5.2.1.9, Table 3.3-1, Table 3.3.2-18, and Table 3.5.2-9 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Revise SLRA Section 3.3.2.1.18 "Materials" and "Aging Effect Requiring Management" sections as follows:

The materials of construction for the Emergency Diesel Generator Fuel Oil and Lubrication Oil components are:

- Carbon steel
- CASS
- Cast iron
- Coating
- Copper alloy
- Glass
- Stainless steel

The following aging effects associated with the Emergency Diesel Generator Fuel Oil and Lubrication Oil components require management:

- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduction of heat transfer

Revise SLRA Section 3.5.2.1.9 "Materials" and "Aging Effect Requiring Management" sections as follows:

The materials of construction for the Emergency Diesel Generator Buildings components are:

- Aluminum
- Carbon steel
- Coating
- Concrete
- Concrete block

- Elastomer, rubber and other similar materials
- Galvanized steel
- Grout
- Stainless steel

The following aging effects associated with the Emergency Diesel Generator Buildings components require management:

- Cracking
- Increase in porosity and permeability
- Loss of bond
- **Loss of coating or lining integrity**
- Loss of material
- Loss of preload
- Loss of sealing
- Reduction in concrete anchor capacity

Revise SLRA Table 3.3-1 item 3.3-1, 138 as follows:

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 138	Any material piping, piping components, heat exchangers, tanks with internal coatings/linings exposed to closed-cycle cooling water, raw water, raw water (potable), treated water, treated borated water, fuel oil, lubricating oil, waste water	Loss of coating or lining integrity due to blistering, cracking, flaking, peeling, delamination, rusting, or physical damage; loss of material or cracking for cementitious coatings/ linings	AMP XI.M42, "Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks"	No	Consistent with NUREG-2191 for components not covered by NRC GL 89-13. This line item is also applied to any material with a coating that is within the scope of NRC GL 89-13. The Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP is used to manage loss of coating or lining integrity for any material with a coating for piping, piping components, heat exchangers, and tanks exposed to treated water, fuel oil or raw water. For items within the scope of NRC GL 89-13, the Open-Cycle Cooling Water System AMP is used to manage the loss of coating or lining integrity.

Add the following line item to SLRA Table 3.3.2-18:

Table 3.3.2-18: Emergency Diesel Generator Fuel and Lubrication Oil – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Tank	Pressure boundary	Coating	Fuel oil (int)	Loss of coating or lining integrity	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	VII.H1.A-416	3.3-1, 138	A

Add the following line item to SLRA Table 3.5.2-9:

Table 3.5.2-9: Emergency Diesel Generator Buildings – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
U4 DOST liner	Pressure boundary	Coating	Fuel oil (int)	Loss of coating or lining integrity	Internal Coatings/ Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks	VII.H1.A-416	3.3-1, 138	A

Associated Enclosures:

None

NRC RAI Letter No. ML18218A199 Dated August 6, 2018

RAI 3.2.2.1.2-1

Background:

SLRA Table 3.1.2-1 states that loss of coating integrity will be managed for the pressurizer surge tank by the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program. The AMR item cites Table 3.2-1, item 3.2.1-072.

UFSAR Table 4.1-3, "Pressurizer and Pressurizer Relief Tank Design Data," states that the pressurizer relief tank has a normal water temperature of 120 degrees F and a design temperature of 340 degrees F. UFSAR Section 4.2.1 states that: (a) "steam safety valves and power-operated relief valves are connected to the pressurizer and discharge to the pressurizer relief tank, where the discharged steam is condensed and cooled by mixing with water;" (b) "[s]team is discharged under the water level to condense and cool by mixing with the water," and (c) "[t]he tank is equipped with a spray, and a drain to the Waste Disposal System, which are operated to cool the tank following a discharge."

Issue:

Although the UFSAR states that the tank has a normal temperature of 120 degrees F, the staff does not know what the internal coatings are constructed of and the maximum temperature rating of the coatings. In addition, the staff does not know whether there are operational controls that would limit the time that the coatings would be exposed to an elevated temperature.

GALL-SLR Report AMP XI.M42 was not written for coatings exposed to elevated temperatures.

Request:

State the coating material type and if possible manufacturer, and the coatings maximum design rating.

Describe any operational controls that would minimize the exposure time to higher temperatures.

FPL Response:

The internal coating for the PTN Unit 3 and 4 pressurizer surge tanks is "Amercoat 55 System". In accordance with the reference below, the Amercoat 55 system is a two-part coating application with both coats of EP series epoxy phenolic (8505 and 8525). The EP series chemical-resistant epoxy phenolic is designed for temperature limits of 180°F (Immersed) and 250°F (Atmospheric).

The high temperature alarm for the pressurizer relief tanks is set at 125°F. The pressurizer relief tank operating procedures contain provisions for maintaining the PTN Unit 3 and 4 pressurizer surge tanks temperature below 120°F. The PTN Unit 3 and 4

pressurizer surge tanks temperature coating system and temperature alarms are consistent with the Indian Point Units 2 and 3 pressurizer surge tanks per the docketed reference below.

Since the pressurizer surge tanks nominal internal temperature is less than 125°F, Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks AMP will adequately manage loss of coating or lining integrity for the pressurizer relief tanks.

References:

Reply to Request for Additional Information for the Review of Indian Point Nuclear Generating Units Nos. 2 and 3, License Renewal Application, SET 2015-02 (ADAMS Accession No. ML15251A237)

Associated SLRA Revisions:

No SLRA changes have been identified as a result of this response.

Associated Enclosures:

None

NRC RAI Letter No. ML18218A199 Dated August 6, 2018

RAI B.2.3.21-1

Background:

SLRA Tables 3.2.2-2, 3.2.2-4, 3.3.2-16, and 3.3.2-18 cite internally coated cast iron heat exchanger shells and non-internally coated cast iron valve bodies, pump casings, and heat exchanger channel heads exposed to treated water. There are AMR items to manage loss of coating integrity (for internally coated cast iron heat exchanger shells) and loss of material; however, there are no AMR items to manage loss of material due to selective leaching by either the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program or the Selective Leaching program.

Issue:

Cast iron components are susceptible to loss of material due to selective leaching. Consistent with the GALL-SLR Report, loss of material due to selective leaching can be managed by either the Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks program (when the components are internally coated) or the Selective Leaching program.

Request:

State the basis for not managing loss of material due to selective leaching for cast iron heat exchanger shells and channel heads, valve bodies, and pump casings exposed to treated water.

FPL Response:

SLRA Tables 3.2.2-2, 3.2.2-4, 3.3.2-16, and 3.3.2-18 are revised to indicate that the Selective Leaching AMP will be used to manage loss of material due to selective leaching for cast iron components. Cast iron components are included with the gray cast iron components for determining sample sizes. Due to the increased numbers of components in the scope of the program, the detail associated with what sample populations contain greater than 35 components is removed from the SLRA. A detailed sampling report will be created as part of AMP implementation to determine all sample populations consistent with GALL-SLR requirements.

Additionally, due to plant specific operating experience of selective leaching being found in the auxiliary feedwater pump lube oil coolers as described in SLRA Section B.2.3.21, the inspections associated with gray cast iron and cast iron components will be periodic and opportunistic rather than one-time.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Table 3.2-1, Table 3.2.2-2, Table 3.2.2-4, Table 3.2.2-16, Table 3.2.2-18, Section 17.2.2.21 and Section B.2.3.21 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Revise SLRA Section 17.2.2.21 paragraphs 3 and 4 as follows:

The scope of this AMP includes components made of gray cast iron, **cast iron,** ductile iron, and copper alloys (except for inhibited brass) that contain greater than 15 percent zinc or greater than 8 percent aluminum exposed to a raw water, treated water, waste water, lubricating oil, or soil environment. Depending on environment, the AMP includes one-time, or opportunistic and periodic visual inspections of selected components that are susceptible to selective leaching, coupled with mechanical examination techniques (e.g., chipping, scraping). Destructive examinations of components to determine the presence of and depth of dealloying through-wall thickness are also conducted. These techniques can determine whether loss of material due to selective leaching is occurring and whether selective leaching will affect the ability of the components to perform their intended function for the SPEO. Inspections are conducted in accordance with site-specific procedures, including inspection parameters such as lighting, distance, offset, and surface conditions. When the acceptance criteria are not met such that it is determined that the affected component should be replaced prior to the end of the SPEO, additional inspections are performed.

Each of the one-time and periodic inspections for these populations at each unit comprises a 3 percent sample or a maximum of 10 components. Gray cast iron**,** **cast iron,** and ductile iron components will be visually and mechanically inspected, **and** the rest will be visually inspected. In addition, for ~~gray cast iron exposed to raw water and ductile iron exposed to raw water (i.e., the only~~ populations having 35 or more components~~)~~, two destructive examinations will be performed for each material and environment population in each 10-year inspection interval at each unit. For each population with less than 35 susceptible components, one destructive examination will be performed.

Revise SLRA Section B.2.3.21 paragraph 1 as follows:

The PTN Selective Leaching AMP is a new condition monitoring program that includes inspection for components that may be susceptible to loss of material due to selective leaching by demonstrating the absence of selective leaching (dealloying) of materials. Materials that may be susceptible include gray cast iron, **cast iron,** ductile iron, and copper alloys (except for inhibited brass) that contain greater than 15 percent zinc or greater than 8 percent aluminum exposed to a raw water, treated water, waste water, lubricating oil, or soil environment.

Revise SLRA Section B.2.3.21 paragraph 3 item 8 as follows:

• Gray cast iron **and cast iron** exposed to treated water (~~One-Time~~ **Periodic and Opportunistic**)

Revise SLRA Section B.2.3.21 paragraph 4 as follows:

Each of the one-time and periodic inspections for these populations at each unit comprises a 3 percent sample or a maximum of 10 components. Gray cast iron, **cast iron,** and ductile iron components will be visually and mechanically inspected, the rest will be visually inspected. In addition, for ~~gray cast iron exposed to raw water and ductile iron exposed to raw water (i.e., the only~~ populations having 35 or more components~~)~~, two destructive examinations will be performed for each material and environment population in each 10-year inspection interval at each unit. For each population with less than 35 susceptible components, one destructive examination will be performed.

Revise SLRA Table 3.2-1, 036 as follows:

Table 3.2-1: Summary of Aging Management Evaluations for the Engineered Safety Features					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.2-1, 036	Gray cast iron, ductile iron piping, piping components exposed to closed-cycle cooling water, treated water	Loss of material due to selective leaching	AMP XI.M33, "Selective Leaching"	No	~~Not applicable.~~ ~~There are no gray cast iron piping or piping components in the Engineered Safety Features systems.~~ **Consistent with NUREG-2191. The Selective Leaching AMP will be used to manage loss of material due to selective leaching in cast iron components exposed to treated water.**

Add the following line item to SLRA Table 3.2.2-2:

Table 3.2.2-2: Containment Spray – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (shell)	Pressure boundary	Cast iron	Treated water (int)	Loss of material	Selective Leaching	V.D1.EP-52	3.2-1, 036	C

Revise the SLRA Notes for Table 3.2.2-2 as follows:

Notes for Table 3.2.2-2:

A. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.

B. Consistent with component, material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP has exceptions to NUREG-2191 AMP description.

C. **Component is different, but consistent with material, environment, aging effect and AMP listed for NUREG-2191 line item. AMP is consistent with NUREG-2191 AMP description.**

H. Aging effect not in NUREG-2191 for this component, material, and environment combination.

Add the following line item to SLRA Table 3.2.2-4:

Table 3.2.2-4: Safety Injection – Summary of Aging Management Evaluation								
Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-2191 Item**	**Table 1 Item**	**Notes**
Heat exchanger (shell)	**Pressure boundary**	**Cast iron**	**Treated water (int)**	**Loss of material**	**Selective Leaching**	**V.D1.EP-52**	**3.2-1, 036**	**C**

Add the following line items to SLRA Table 3.3.2-16:

Table 3.3.2-16: Emergency Diesel Generator Cooling Water – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Pump casing	Pressure boundary	Cast iron	Treated water (int)	Loss of material	Selective Leaching	VII.C2.A-50	3.3-1, 072	A
Valve body	Pressure boundary	Cast iron	Treated water (int)	Loss of material	Selective Leaching	VII.C2.A-50	3.3-1, 072	A

Add the following line item to SLRA Table 3.3.2-18:

Table 3.3.2-18: Emergency Diesel Generator Fuel and Lubricating Oil – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (channel head)	Pressure boundary	Cast iron	Treated water (int)	Loss of material	Selective Leaching	VII.C2.A-50	3.3-1, 072	C

Associated Enclosures:

None

NRC RAI Letter No. ML18218A199 Dated August 6, 2018

4. Fire Water System

Regulatory Basis:

Section 54.21(a)(3) of 10 CFR requires an applicant to demonstrate that the effects of aging for structures and components will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation. One of the findings that the staff must make to issue a renewed license (10 CFR Section 54.29(a)) is that actions have been identified and have been or will be taken with respect to managing the effects of aging during the subsequent period of extended operation on the functionality of structures and components that have been identified to require review under 10 CFR Section 54.21, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis (CLB). In order to complete its review and enable making a finding under 10 CFR Section 54.29(a), the staff requires additional information in regard to the matters described below.

RAI B.2.3.16-1

Background:

1. SLRA Section B.2.3.16 cites an enhancement, Enhancement No. 4, to the Fire Water System Program as follows:

   > Update AMP [aging management program] inspection/testing procedure(s) and develop new procedures to state that testing and visual inspections are performed in accordance with [GALL-SLR Report AMP] Table XI.M27-1 from NUREG-2191 [Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report]. This table, "Fire Water System Inspection and Testing Recommendations," is based on NFPA [National Fire Protection Association] 25 [Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems] (Reference B.3.131), 2011 edition. Unless recommended otherwise, external visual inspections are to be conducted on an RFO [refueling outage] interval.

   The program basis document, reviewed during the in-office audit, cites a list of procedures and corresponding Table XI.M27-1 tests or inspections. It does not provide a description of the required changes, nor does SLRA Section B.2.3.16.

   SLRA Section B.2.3.16, Enhancement No. 4 states, "[update inspection/testing procedures] to state that testing and visual inspections are performed in accordance with Table XI.M27-1..."

2. Procedure 0-OSP-016.30, "Fire Main Post Indicator Valve (PIV) Leak/Flow Path Valve Surveillance Test and System Flush," does not include a step to verify that the hydrant barrel drains in 60 minutes.

3. The fire water system program basis document states that procedure 0-ADM-016, "Fire Protection Program," addresses the ability to maintain the required system pressures.
4. Procedure 4-SMM-016.02A, "Spray/Sprinkler System Insp. (EDG 4A Preaction Deluge Valve 4-10-1112 Partial Flow Test, Zone 138)," allows removal and cleaning of obstructed spray sprinklers.
5. Procedure 0-SFP-106.5, "Fire Protection Equipment Surveillance," states that the acceptance criteria for the inspection of internals for the raw water tanks is no signs of age-related degradation which could compromise the integrity of the protection system.
6. The fire water system program basis document states that procedure PI-AA-104-1000, "Condition Reporting," addresses corrective actions associated with: (a) conducting evaluations to determine if deposits need to be removed to determine if loss of material has occurred; and (b) conducting a flush in accordance with the guidance in NFPA 25 Appendix D.5, "Flushing Procedures," when loose fouling products that could cause flow blockage in sprinklers is detected.

Issue:

1. Enhancement No. 4, along with the additional information provided in the program basis document, lacks sufficient detail for the staff to have reasonable assurance that all plant-specific procedure change actions will be identified in relation to fire water system inspection and test procedures conducted during the subsequent period of extended operation. For example, Section 6.0, "Implementing Documents," in the program basis document states the following in relation to procedure changes associated with internal tank inspections:

   > Perform a fire water storage tank interior inspection every five years that includes inspections for signs of pitting, spalling, rot, waste material and debris, and aquatic growth. Also, revise existing procedures to perform a non-destructive examination to determine wall thickness whenever degradation is identified during internal tank inspections.

   This description of changes to internal tank inspections lacks details related to other tests and inspections recommended in Table XI.M27-1 (NFPA 25 Section 9.2.7, "Tests During Interior Inspections") when signs of interior pitting, corrosion, or failure of coatings are detected during internal tank inspections. Examples include vacuum box testing and various coating inspections techniques that are beyond those recommended in AMP XI.M42, "Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks;" however, recommended in AMP XI.M27, "Fire Water System."

   Some inspections cited in Table XI.M27-1 utilize techniques other than visual methods (e.g., NFPA 25, "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," Section 9.2.7 (3) ultrasonic thickness

measurements of fire water storage tank bottoms). Flushes are recommended in addition to tests and visual inspections.

2. NFPA-25, "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," Section 7.3.2.4, "Hydrants," states that full drainage of dry barrel hydrants should take no longer than 60 minutes. Meeting this section of NFPA-25 is recommended by GALL-SLR Report AMP XI.M27, Table XI.M27-1, "Fire Water System Inspection and Testing Recommendations." Verifying the drain time ensures that potential accumulation of debris will not prevent the drainage of the barrel, which can ensure that the hydrant will not freeze and result in a loss of intended function.

3. GALL-SLR Report AMP XI.M27 recommends that:

   > The water-based fire protection systems are normally maintained at required operating pressure and monitored in such a way that loss of system pressure is immediately detected and corrected when acceptance criteria are exceeded. Continuous system pressure monitoring or equivalent methods (e.g., number of jockey fire pump starts or run time) are conducted.

   Based on a review of 0-ADM-016, there are no surveillance activities that address routine monitoring of the system pressure such that an adverse pressure trend is detected promptly and corrected.

4. The staff recognizes that removal and cleaning of deluge nozzles is a normal acceptable practice. However, removal and cleaning of sprinklers is not allowed by NFPA 25 Section 5.2.1, "Sprinklers," due to the potential for undetected damage to the sprinkler during the cleaning process. Meeting this section of NFPA-25 is recommended by GALL-SLR Report AMP XI.M27, Table XI.M27-1. Based on the staff's review of 4-SMM-016.02A, it would appear that the subject "spray sprinklers" are actually deluge nozzles; however, the staff cannot confirm that this is the case across all of the plant-specific procedures.

5. GALL-SLR Report AMP XI.M27 recommends that the acceptance criterion for loss of material is based on minimum design wall thickness. The acceptance criteria in 0-SFP-106.5 lacks sufficient clarity for the staff to complete its evaluation.

6. GALL-SLR Report AMP XI.M27 recommends that: (a) an evaluation be conducted to determine if deposits need to be removed to determine if loss of material has occurred; and (b) flush be conducted in accordance with the guidance in NFPA 25 Appendix D.5, "Flushing Procedures," when loose fouling products that could cause flow blockage in sprinklers is detected.

Request:

1. Respond to the following:
    a. For existing procedures that need to be updated, provide a description of the specific changes necessary for the fire water system inspections and tests to be consistent with GALL-SLR Report AMP XI.M27 Table XI.M27-1. Alternatively, state and justify any exceptions that are deemed necessary.
    b. For new procedures that need to be developed (i.e., sprinkler testing, water storage tank inspections, main drain tests, obstruction inspections), provide a summary of the changes sufficient to demonstrate that the procedure will be consistent with the inspections and tests described in XI.M27 Table XI.M27-1. For example, see Enhancement No. 8 related to bottom surface inspections of tanks. Alternatively, state and justify any exceptions that are deemed necessary.
    c. State the basis for why Enhancement No. 4 states that only changes to tests and visual inspections will be consistent with Table XI.M27-1.
2. State the basis for why procedure 0-OSP-016.30 is not consistent with GALL-SLR Report AMP XI.M27 in regard to verifying that hydrant barrels drain in 60 minutes.
3. State the basis for why procedure 0-ADM-016 is not consistent with the GALL-SLR Report AMP XI.M27 in regard to routine monitoring of the system pressure such that an adverse pressure trend is detected promptly and corrected.
4. State whether the "spray sprinklers" cited in plant-specific inspection procedures where removal and cleaning is allowed are actually deluge nozzles. If not, state the basis for allowing removal and cleaning of the "spray sprinklers."
5. State the basis for not using minimum design wall thickness as the acceptance criterion when evaluating loss of material.
6. State the basis for why procedure PI-AA-104-1000 is not consistent with GALL-SLR Report AMP XI.M27 in regard to corrective actions associated with: (a) conducting evaluations to determine if deposits need to be removed to determine if loss of material has occurred; and (b) conducting a flush in accordance with the guidance in NFPA 25 Appendix D.5, "Flushing Procedures," when loose fouling products that could cause flow blockage in sprinklers is detected.

FPL Response:

RAI B.2.3.16-1 Request 1:

RAI B.2.3.16-1 Request 1 Items a, b, and c are addressed in the following paragraphs and tables.

a. Descriptions of the specific changes necessary to the existing fire water system inspection and test procedures to implement the enhancements identified in SLRA Section B.2.3.16, and demonstrate consistency with NUREG-2191, Table XI.M27-1, are provided in the following table. No exceptions to the GALL-SLR report were determined to be necessary.

Table RAI B.2.3.16-1.a: Existing Procedures

Description	NFPA 25 Section	Implementing Procedure to be Revised	Procedure Title	Required Enhancements
Sprinkler Systems				
Sprinkler inspections	5.2.1.1	3-SMM-016.02A	Spray/Sprinkler System Insp. (EDG 3A Preaction Valve 3-10-847 Partial Flow Test, Zone 73 & 75)	These procedures are currently performed every 18 months (refueling outage interval), which meets the interval requirements of NUREG-2191 Table XI.M27-1 Note 10. Each of these procedures will be enhanced to incorporate the requirements of NFPA 25 Section 5.2.1.1 to ensure that sprinklers are visually inspected from the floor level and meet the acceptance criteria, which include no signs of leakage, corrosion, foreign materials, paint (unless painted by manufacturer), physical damage, loading, and loss of fluid in glass bulb heat responsive elements. Additionally, sprinklers shall be installed in the correct orientation (e.g., upright, pendent, or sidewall). Any sprinkler that does not meet these criteria shall be replaced. Note that the acceptance criteria related to glass bulb heat responsive elements do not apply to the following procedures since the systems they inspect include open head sprinklers only:
		3-SMM-016.02B	Spray/Sprinkler System Insp. (EDG 3B Preaction Valve 10-844 Partial Flow Test, Zone 72 & 74)	
		3-SMM-016.02D	Spray/Sprinkler System Insp. (CCW HX Area Deluge Valve 3-10-837 Partial Flow Test, Zone 54A)	
		3-SMM-016.02E	Spray/Sprinkler System Insp. (CCW HX Area Deluge Valve 3-10-839 Partial Flow Test, Zone 54B)	
		3-SMM-016-02F	Spray/Sprinkler System Insp. (Charging PMP Preaction Del. VLVE 3-10-841 Partial Flow Test, Zone 55)	
		4-SMM-016.02	Spray/Sprinkler System Insp (Aux Bldg N/S Breezeway (Cable Riser Area) F.P. VLV 10-850, Zone 79A)	
		4-SMM-016.02A	Spray/Sprinkler System Insp. (EDG 4A Preaction Deluge Valve 4-10-1112 Partial Flow Test, Zone 138)	

Table RAI B.2.3.16-1.a: Existing Procedures

Description	NFPA 25 Section	Implementing Procedure to be Revised	Procedure Title	Required Enhancements
		4-SMM-016.02B	Spray/Sprinkler System Insp. (EDG 4B Preaction Deluge Valve 4-10-1113 Partial Flow Test, Zone 133)	• 3-SMM-016.02D • 3-SMM-016.02E • 4-SMM-016.02 • 4-SMM-016.02D • 4-SMM-016.02E
		4-SMM-016.02C	EDG XFER PMP 4A&4B Rooms Alarm Check VLV 4-10-1122 Flow Test, Zone 136&141/Sprinkler Inspection	
		4-SMM-016.02D	Spray/Sprinkler System Insp (CCW HX Area Deluge Valve 4-10-833 Partial Flow Test, Zone 47A)	
		4-SMM-016.02E	Spray/Sprinkler System Insp (CCW HX Area Deluge Valve 4-10-835 Partial Flow Test, Zone 47B)	
		4-SMM-016.02F	Spray/Sprinkler System Insp. (Charging PMP Preaction Del. VLV 4-10-830 Partial Flow Test, Zone 45)	

Table RAI B.2.3.16-1.a: Existing Procedures

Description	NFPA 25 Section	Implementing Procedure to be Revised	Procedure Title	Required Enhancements
Standpipe and Hose Systems				
Flow tests	6.3.1	0-OSP-016.30	Fire Main Post Indicator Valve (PIV) Leak/Flow Path Valve Surveillance Test and System Flush	This test procedure will be enhanced to ensure the following requirements of NFPA 25, Section 6.3.1 and subsections are met: 6.3.1: Flow Tests. 6.3.1.1*: A flow test shall be conducted every 5 years at the hydraulically most remote hose connections of each zone of an automatic standpipe system to verify the water supply still provides the design pressure at the required flow. 6.3.1.2: Where a flow test of the hydraulically most remote outlet(s) is not practical, the authority having jurisdiction shall be consulted for the appropriate location for the test. 6.3.1.3: All systems shall be flow tested and pressure tested at the requirements for the design criteria in effect at the time of the installation. 6.3.1.3.1: The actual test method(s) and performance criteria shall be discussed in advance with the authority having jurisdiction.

Table RAI B.2.3.16-1.a: Existing Procedures

Description	NFPA 25 Section	Implementing Procedure to be Revised	Procedure Title	Required Enhancements
				6.3.1.4: Standpipes, sprinkler connections to standpipes, or hose stations equipped with pressure reducing valves or pressure regulating valves shall have these valves inspected, tested, and maintained in accordance with the requirements of NFPA-25, Chapter 13. 6.3.1.5: A main drain test shall be performed on all standpipe systems with automatic water supplies in accordance with the requirements of NFPA-25, Chapter 13. 6.3.1.5.1: The test shall be performed at the low point drain for each standpipe or the main drain test connection where the supply main enters the building (when provided). 6.3.1.5.2: [Not applicable per NUREG-2191 Table XI.M27-1 Note 9. See below.] Per NUREG-2191 Table XI.M27-1 Note 9, calibration of measuring and test equipment (i.e., pressure gauges provided for flow tests) is conducted in accordance with plant-specific procedures in lieu of NFPA 25 requirements.
Private Fire Service Mains				

Table RAI B.2.3.16-1.a: Existing Procedures

Description	NFPA 25 Section	Implementing Procedure to be Revised	Procedure Title	Required Enhancements
Underground and exposed piping flow tests	7.3.1	0-OSP-016.29	Fire Main Hydraulic Gradient Flow Test	This test procedure will be enhanced to ensure the following requirements from NFPA 25, Section 7.3.1 and subsections are met: 7.3.1*: Underground and Exposed Piping Flow Tests. Underground and exposed piping shall be flow tested to determine the internal condition of the piping at minimum 5-year intervals. 7.3.1.1: Flow tests shall be made at flows representative of those expected during a fire, for the purpose of comparing the friction loss characteristics of the pipe with those expected for the particular type of pipe involved, with due consideration given to the age of the pipe and to the results of previous flow tests. 7.3.1.2: Any flow test results that indicate deterioration of available water flow and pressure shall be investigated to the complete satisfaction of the authority having jurisdiction to ensure that the required flow and pressure are available for fire protection. 7.3.1.3: Where underground piping supplies individual fire sprinkler, standpipe, water spray, or foam-water sprinkler

Table RAI B.2.3.16-1.a: Existing Procedures

Description	NFPA 25 Section	Implementing Procedure to be Revised	Procedure Title	Required Enhancements
				systems and there are no means to conduct full flow tests, tests generating the maximum available flows shall be permitted. Per NUREG-2191 Table XI.M27-1 Note 9, calibration of measuring and test equipment is conducted in accordance with plant-specific procedures in lieu of NFPA 25 requirements.
Hydrants	7.3.2	0-OSP-016.30	Fire Main Post Indicator Valve (PIV) Leak/Flow Path Valve Surveillance Test and System Flush	This procedure has its fire hydrant flushing test performed every 18 months (refueling outage interval) which meets the interval requirements of NUREG-2191, Table XI.M27-1, Note 10. This test ensures that the hydrants and their respective piping systems are functioning properly. This procedure will be enhanced to clarify the other requirements of NFPA 25, Section 7.3.2 subsections: 7.3.2.1: Each hydrant shall be opened fully and water flowed until all foreign material has cleared. [Procedure already performs this.] 7.3.2.2: Flow shall be maintained for not less than 1 minute. [Procedure already performs this.]

Table RAI B.2.3.16-1.a: Existing Procedures

Description	NFPA 25 Section	Implementing Procedure to be Revised	Procedure Title	Required Enhancements
				7.3.2.3: After operation, dry barrel and wall hydrants shall be observed for proper drainage from the barrel. 7.3.2.4: Full drainage shall take no longer than 60 minutes. 7.3.2.5: Where soil conditions or other factors are such that the hydrant barrel does not drain within 60 minutes, or where the groundwater level is above that of the hydrant drain, the hydrant drain shall be plugged and the water in the barrel shall be pumped out.

Table RAI B.2.3.16-1.a: Existing Procedures

Description	NFPA 25 Section	Implementing Procedure to be Revised	Procedure Title	Required Enhancements
				7.3.2.6: [Not applicable as no Turkey Point hydrants are subject to freezing weather, and this is supported by the minimum design temperature of 39°F for the refueling water storage tanks (outdoors) per 5610-062-DB-002.] If loose deposits are identified in the piping, and the evaluation determines that the deposits must be removed, then the piping is required to be flushed repeatedly, in accordance with NFPA 25 Annex D.5, until it is determined that either no deposits are left or that the remaining deposits pose no blockage threat. Areas where excessive deposits are found will undergo more thorough volumetric wall testing to ensure minimum wall thickness is met. See the response to RAI B.2.3.16 Request 2 for enhancements associated with the drainage requirements of NFPA 25 Sections 7.3.2.4 and 7.3.2.5 Per NUREG-2191 Table XI.M27-1 Note 9, calibration of measuring and test equipment is conducted in accordance with plant-specific procedures in lieu of NFPA 25 requirements.

Table RAI B.2.3.16-1.a: Existing Procedures

<table>
<tr><th>Description</th><th>NFPA 25 Section</th><th>Implementing Procedure to be Revised</th><th>Procedure Title</th><th>Required Enhancements</th></tr>
<tr><td colspan="5">Fire Pumps</td></tr>
<tr><td rowspan="2">Suction screens</td><td rowspan="2">8.3.3.7</td><td>0-OSP-016.1</td><td>Electric Driven Fire Pump Annual Surveillance Test</td><td rowspan="2">These procedures are currently performed annually, which meets the interval requirements of NFPA 25, Section 8.3.3.7.
These procedures do not currently inspect the electrical and diesel fire pump suction screens for debris and obstructions. As a result, this procedure will be enhanced to include the following inspection steps and acceptance criteria of NFPA 25, Section 8.3.3.7:
After the water flow portions of the annual test, or fire protection system activations, the suction screens shall be inspected and cleared of any debris or obstructions. The acceptance criteria shall be no debris or obstructions on the pump suction screens.</td></tr>
<tr><td>0-OSP-016.2</td><td>Diesel Driven Fire Pump Annual Surveillance Test</td></tr>
</table>

Table RAI B.2.3.16-1.a: Existing Procedures

Description	NFPA 25 Section	Implementing Procedure	Procedure Title	Required Enhancements
Water Spray Fixed Systems				
Strainers (after each system actuation)	10.2.1.6, 10.2.1.7, 10.2.7	0-SMM-016.10	C-Bus Transformer Fire Suppression System 18 Month Functional Test	Except for the startup transformer procedures (3-SMM-016.9 and 4-SMM-016.9), these functional test procedures are performed every 18 months (refueling outage interval), which meets the interval requirements of NUREG-2191, Table XI.M27-1, Note 10. Procedures 3-SMM-016.9 and 4-SMM-016.9 are performed every 24 months, which is within the NFPA 25, Table 10.1.1.2 requirement of a 5-year maximum interval for mainline strainers. Note that no nozzle strainers are used in the PTN sprinkler systems, so the annual inspection of nozzle strainers (NFPA 25, Sections 10.2.1.6 and 10.2.7.2) does not apply. These procedures will be enhanced to meet the inspection, flushing, and parts replacement and repair requirements of NFPA 25, Sections 10.2.1.7, 10.2.7, and associated subsections. These enhancements include flushing the mainline strainers until clear after each operation or flow test, inspecting and cleaning the strainers in accordance with the manufacturer's instructions, and
		3-SMM-016.07	Turbine Lube Oil Reservoir Fire Suppression System 18 Month Functional Test	
		3-SMM-016.8	Main Transformer Fire Suppression System 18 Month Functional Test	
		3-SMM-016.9	Startup Transformer Fire Suppression System Functional Test	
		3-SMM-016.11	Auxiliary Transformer and Hydrogen Seal Oil Unit Fire Suppression System Functional Test	
		4-SMM-016.07	Turbine Lube Oil Reservoir Fire Suppression System 18 Month Functional Test	
		4-SMM-016.8	Main Transformer Fire Suppression System 18 Month Functional Test	
		4-SMM-016.9	Startup Transformer Fire Suppression System Functional Test	

Table RAI B.2.3.16-1.a: Existing Procedures

Description	NFPA 25 Section	Implementing Procedure	Procedure Title	Required Enhancements
		4-SMM-016.11	Auxiliary Transformer and Hydrogen Seal Oil Unit Fire Suppression System Functional Test	replacing or repairing damaged or corroded parts
Operation test (refueling outage interval)	10.3.4.3	0-SMM-016.18	Open Head Spray/Sprinkler 3 Year Air Flow Test	Except for 0-SMM-016.18, 3-SMM-016.9, and 4-SMM-016.9, these functional test procedures are performed every 18 months (refueling outage interval). Procedures 3-SMM-016.9 and 4-SMM-016.9 are performed every 24 months and 0-SMM-016.18 is performed every 3 years. All of these test intervals meet the 3-year maximum interval requirement of NUREG-2191, Table XI.M27-1, Note 8. Except for 0-SMM-016.18, these procedures test open head spray nozzles with water and meet the NFPA 25, Section 10.3.4.3.1 requirement by ensuring that spray patterns are not impeded by plugged nozzles, that nozzles are correctly positioned, and that obstructions do not prevent discharge patterns from wetting surfaces to be protected. Procedure 0-SMM-016.18 tests its nozzles with air rather than water and is the only procedure that applies to NFPA 25, Section
		0-SMM-016.10	C-Bus Transformer Fire Suppression System 18 Month Functional Test	
		3-SMM-016.07	Turbine Lube Oil Reservoir Fire Suppression System 18 Month Functional Test	
		3-SMM-016.8	Main Transformer Fire Suppression System 18 Month Functional Test	
		3-SMM-016.9	Startup Transformer Fire Suppression System Functional Test	
		3-SMM-016.11	Auxiliary Transformer and Hydrogen Seal Oil Unit Fire Suppression System 18 Month Functional Test	
		4-SMM-016.07	Turbine Lube Oil Reservoir Fire Suppression System 18 Month Functional Test	

Table RAI B.2.3.16-1.a: Existing Procedures

Description	NFPA 25 Section	Implementing Procedure	Procedure Title	Required Enhancements
		4-SMM-016.8	Main Transformer Fire Suppression System 18 Month Functional Test	10.3.4.3.1.1. This procedure meets the requirement of ensuring that nozzles are inspected for proper orientation and that nozzles are not obstructed. All of these procedures will be enhanced to meet the requirements of NFPA 25, Section 10.3.4.3.2 to retest systems after cleaning if obstructions are found. If loose deposits are identified in the piping, and the evaluation determines that the deposits must be removed, then the piping is required to be flushed repeatedly, in accordance with NFPA 25 Annex D.5, until it is determined that either no deposits are left or that the remaining deposits pose no blockage threat. Areas where excessive deposits are found will undergo more thorough volumetric wall testing to ensure minimum wall thickness is met.
		4-SMM-016.9	Startup Transformer Fire Suppression System Functional Test	
		4-SMM-016.11	Auxiliary Transformer and Hydrogen Seal Oil Unit Fire Suppression System Functional Test	

Table RAI B.2.3.16-1.a: Existing Procedures

Description	NFPA 25 Section	Implementing Procedure	Procedure Title	Required Enhancements
Water Storage Tanks				
Exterior Inspections	9.2.5.5	0-SFP-016.5	Fire Protection Equipment Surveillance	This procedure requires visual inspection of the non-insulated raw water tank and supporting structure's painted or coated exterior surfaces for signs of degradation on an annual or refueling outage interval. This inspection will be in accordance with NFPA 25, Section 9.2.5.5, and NUREG-2191 Table XI.M27-1 Note 10.

Table RAI B.2.3.16-1.a: Existing Procedures

Description	NFPA 25 Section	Implementing Procedure	Procedure Title	Required Enhancements
General				
General	-	0-ADM-016	Fire Protection Program	This procedure governs the fire water system AMP. This broad procedure will be enhanced to state the new requirements that are implemented by the subordinate procedures. These requirements include new sample sizes, inspection/test frequencies, inspection/testing methods, acceptance criteria, trending, and corrective actions. Additionally, 0-ADM-016 Sections 5.6.4.1, 5.6.4.2, 5.6.4.4, and 5.6.4.5 will be updated to clarify that fouling and sediment blockage will be inspected for, evaluated, and

Table RAI B.2.3.16-1.a: Existing Procedures

Description	NFPA 25 Section	Implementing Procedure	Procedure Title	Required Enhancements
				trended. Wall thicknesses shall meet and be projected to meet their minimum required thickness until the next inspection. Any component/nozzle blockage will be corrected and inspections/flushing must occur before blockage is projected to occur. Procedure 0-ADM-016, "Fire Protection Program," will also be revised to include a requirement to ensure that fire water systems are normally maintained at required operating pressure and monitored in such a way that loss of system pressure is immediately detected and corrected when acceptance criteria are exceeded. The monitoring will include continuous fire water system pressure monitoring or an equivalent method (such as monitoring the number of jockey fire pump starts or run time).
General	-	0-ADM-016.3	Fire Protection Impairments (FPI)	This procedure will be enhanced to state that if an inspection or test of fire protection or fire water system components does not meet acceptance criteria, then an FPI tag shall be created in accordance with this procedure and the deficient component(s) shall remain tagged until acceptance criteria are met.

Table RAI B.2.3.16-1.a: Existing Procedures

Description	NFPA 25 Section	Implementing Procedure	Procedure Title	Required Enhancements
General	-	0-ADM-016.7	Performance Based Optimization Evaluations for Fire Protection	This procedure will be revised to incorporate the guidance of EPRI 1006756, "Fire Protection Equipment Surveillance Optimization and Maintenance Guide".
General	-	0-ADM-016.9	Fire Protection Performance and Trending	This procedure will be enhanced to state: • Where practical, identified component degradation is projected until the next scheduled inspection/test. • Results are evaluated against acceptance criteria to confirm that the timing of subsequent inspections will maintain the components' intended functions throughout the SPEO based on the projected rate of degradation. • Results of flow testing, flushes, and wall thickness measurements are monitored and trended by either the Engineering or Fire Protection Department per instructions of the specific test/inspection procedure. • Degradation identified by flow testing, flushes, and inspections is evaluated. If the condition of the piping/component does not meet acceptance criteria, then a condition report is written and the component is evaluated for repair/replacement.

Table RAI B.2.3.16-1.a: Existing Procedures

Description	NFPA 25 Section	Implementing Procedure	Procedure Title	Required Enhancements
General	-	0-ADM-016.9	Fire Protection Performance and Trending	• Additional tests are performed if a flow test or a main drain test does not meet acceptance criteria due to current or projected degradation. The number of increased tests is determined in accordance with the PTN Corrective Action Program; however, there are no fewer than two additional tests for each failed test. The additional inspections/tests are completed within the intervals in which the original tests were conducted. If subsequent tests do not meet acceptance criteria, an extent-of-condition/cause analysis is conducted to determine the extent of further testing, which could include inspections of additional components with the same material, environment, and aging effect combinations. • For sampling-based inspections, results are evaluated against acceptance criteria to confirm that the sampling bases (e.g., selection, size, inspection frequency/interval) will maintain the components' intended functions throughout the SPEO based on the

Table RAI B.2.3.16-1.a: Existing Procedures

Description	NFPA 25 Section	Implementing Procedure	Procedure Title	Required Enhancements
				projected rate and extent of degradation.
General	-	0-ADM-016.10	Implementation of the NFPA 805 Monitoring Program	This procedure will be revised to identify monitoring and trending steps that will also be applicable to PTN during the SPEO.

b. Descriptions of new procedures to be developed to implement the enhancements identified in SLRA Section B.2.3.16, and demonstrate consistency with the inspections and tests described in NUREG-2191, Table XI.M27-1, are provided in Table RAI B.2.3.16-1.b below. No exceptions to the GALL-SLR report were determined to be necessary.

Table RAI B.2.3.16-1.b: New Procedures

Description	NFPA 25 Section	Requirements
Sprinkler Systems		
Sprinkler Testing	5.3.1	A new procedure will be prepared and implemented to incorporate the following sprinkler testing instructions of NFPA 25, Section 5.3.1 subsections. Steps with asterisks have additional clarifying information in NFPA 25, Annex A. The required steps and information are as follows: 5.3.1.1*: Where required by this section, sample sprinklers shall be submitted to a recognized testing laboratory acceptable to the authority having jurisdiction for field service testing. 5.3.1.1.1: Where sprinklers have been in service for 50 years, they shall be replaced or representative samples from one or more sample areas shall be tested. 5.3.1.1.1.1: Test procedures shall be repeated at 10-year intervals. 5.3.1.1.1.2: Sprinklers manufactured prior to 1920 shall be replaced. 5.3.1.1.1.3*: Sprinklers manufactured using fast-response elements that have been in service for 20 years shall be replaced, or representative samples shall be tested and then retested at 10-year intervals. 5.3.1.1.1.4*: Representative samples of solder-type sprinklers with a temperature classification of extra high [325°F (163°C)] or greater that are exposed to semi-continuous to continuous maximum allowable ambient temperature conditions shall be tested at 5-year intervals. 5.3.1.1.1.5: Where sprinklers have been in service for 75 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory acceptable to the authority having jurisdiction for field service testing and repeated at 5-year intervals.

Table RAI B.2.3.16-1.b: New Procedures

Description	NFPA 25 Section	Requirements
		5.3.1.1.1.6*: Dry sprinklers that have been in service for 10 years shall be replaced or representative samples shall be tested and then retested at 10-year intervals. 5.3.1.1.2*: Where sprinklers are subjected to harsh environments, including corrosive atmospheres and corrosive water supplies, on a 5-year basis, either sprinklers shall be replaced or representative sprinkler samples shall be tested. 5.3.1.1.3: Where historical data indicate, longer intervals between testing shall be permitted. 5.3.1.2*: A representative sample of sprinklers for testing per NFPA 25, Section 5.3.1.1.1, shall consist of a minimum of not less than four sprinklers or 1 percent of the number of sprinklers per individual sprinkler sample, whichever is greater. 5.3.1.3: Where one sprinkler within a representative sample fails to meet the test requirement, all sprinklers within the area represented by that sample shall be replaced. 5.3.1.3.1: Manufacturers shall be permitted to make modifications to their own sprinklers in the field with listed devices that restore the original performance as intended by the listing, where acceptable to the authority having jurisdiction. If loose deposits are identified in the piping, and the evaluation determines that the deposits must be removed, then the piping is required to be flushed repeatedly, in accordance with NFPA 25 Annex D.5, until it is determined that either no deposits are left or that the remaining deposits pose no blockage threat. Areas where excessive deposits are found will undergo more thorough volumetric wall testing to ensure minimum wall thickness is met.

Table RAI B.2.3.16-1.b: New Procedures

Description	NFPA 25 Section	Requirements

		Per NUREG-2191 Table XI.M27-1, the following notes also apply: • Items in areas that are inaccessible because of safety considerations such as those raised by continuous process operations, radiological dose, or energized electrical equipment are inspected during each scheduled shutdown but not more often than every refueling outage interval. • Calibration of measuring and test equipment is conducted in accordance with plant-specific procedures in lieu of NFPA 25 requirements. Note that a representative sample of sprinklers in wet pipe systems will be subject to new 5-year interval testing in accordance with NFPA 25, Section 5.3.1.1.2, as listed above.

Table RAI B.2.3.16-1.b: New Procedures

Description	**NFPA 25 Section**	**Requirements**
Water Storage Tanks		
Interior Inspections	9.2.6; 9.2.7	A new procedure will be prepared and implemented to perform a raw water tank (RWT) interior inspection. This procedure will incorporate the following instructions for the interior inspections of water storage tanks from NUREG-2191, Table XI.M27-1, and NFPA 25, Sections 9.2.6, 9.2.7, and subsections. Steps with asterisks have additional clarifying information in NFPA 25, Annex A. The required steps and information are as follows: 9.2.6.1.1*: The interior of steel tanks without corrosion protection shall be inspected every 3 years. [Note A.9.2.6.1.1 discusses interior paint/coating, which is a type of corrosion protection applied to the RWTs.] 9.2.6.1.2: [Not applicable since the RWT interior does have corrosion protection; an interior coating.] 9.2.6.2: Where interior inspection is made by means of underwater evaluation, silt shall first be removed from the tank floor. 9.2.6.3: The tank interior shall be inspected for signs of pitting, corrosion, spalling, rot, other forms of deterioration, waste materials and debris, aquatic growth, and local or general failure of interior coating. 9.2.6.4: Steel tanks exhibiting signs of interior pitting, corrosion, or failure of coating shall be tested in accordance with NFPA 25, Section 9.2.7. 9.2.6.5*: Tanks on ring-type foundations with sand in the middle shall be inspected for evidence of voids beneath the floor. [This inspection can be performed by looking for dents on the tank floor. Additionally, walking on the tank floor and looking for buckling of the floor will identify problem areas.] 9.2.6.6: The heating system and components including piping shall be inspected. 9.2.6.7: The anti-vortex plate shall be inspected for deterioration or blockage.

Table RAI B.2.3.16-1.b: New Procedures

Description	**NFPA 25 Section**	**Requirements**
		9.2.7: Tests During Interior Inspection. Where a drained interior inspection of a steel tank is required by 9.2.6.4, the following tests shall be conducted: (1) [Not applicable per NUREG-2191 Table XI.M27-1 Note 4. See below.] (2) [Not applicable per NUREG-2191 Table XI.M27-1 Note 4. See below.] (3) Nondestructive ultrasonic readings shall be taken to evaluate the wall thickness where there is evidence of pitting or corrosion. (4) [Not applicable per NUREG-2191 Table XI.M27-1 Note 4. See below.] (5) Tank bottoms shall be tested for metal loss and/or rust on the underside by use of ultrasonic testing where there is evidence of pitting or corrosion. Removal, visual inspection, and replacement of random floor coupons shall be an acceptable alternative to ultrasonic testing. (6) Tanks with flat bottoms shall be vacuum-box tested at bottom seams in accordance with test procedures found in NFPA 22, Standard for Water Tanks for Private Fire Protection. NUREG-2191 Table XI.M27-1 Note 4 is in regard to NFPA 25 Sections 9.2.6.4 and 9.2.7: When degraded coatings are detected, the acceptance criteria and corrective action recommendations in GALL-SLR Report AMP XI.M42 are followed in lieu of Section 9.2.7 (1), (2), and (4). When interior pitting or general corrosion (beyond minor surface rust) is detected, tank wall thickness measurements are conducted as stated in NFPA 25 Section 9.2.7 (3) in the vicinity of the loss of material. Vacuum box testing as stated in Section 9.2.7 (6) is conducted when pitting, cracks, or loss of material is detected in the immediate vicinity of welds. This new procedure will also incorporate the activities detailed in response to RAI B.2.3.16-3. Additionally, per NUREG-2191 Table XI.M27-1, calibration of measuring and test equipment is conducted in accordance with plant-specific procedures in lieu of NFPA 25 requirements.

Table RAI B.2.3.16-1.b: New Procedures

Description	NFPA 25 Section	Requirements
Valves and System-Wide Testing		
Main Drain Test	13.2.5	A new procedure will be prepared and implemented to incorporate the following instructions and requirements for the fire main drain test from NFPA 25, Section 13.2.5 and subsections. Steps with asterisks have additional clarifying information in NFPA 25, Annex A. The required steps and information are as follows: 13.2.5*: A main drain test shall be conducted annually at each water-based fire protection system riser to determine whether there has been a change in the condition of the water supply piping and control valves and any time the control valve is closed and reopened at system riser. [Note that NUREG-2191, Table XI.M27-1, Note 10 allows this test to be performed on a refueling outage interval (i.e., every 18 months) instead of annually.] 13.2.5.1: In systems where the sole water supply is through a backflow preventer and/or pressure reducing valves, the main drain test of at least one system downstream of the device shall be conducted on a quarterly basis. 13.2.5.2: When there is a 10 percent reduction in full flow pressure when compared to the original acceptance test or previously performed tests, the cause of the reduction shall be identified and corrected if necessary. Per NUREG-2191 Table XI.M27-1, the following notes also apply: • Items in areas that are inaccessible because of safety considerations such as those raised by continuous process operations, radiological dose, or energized electrical equipment are inspected during each scheduled shutdown but not more often than every refueling outage interval. • Calibration of measuring and test equipment is conducted in accordance with plant-specific procedures in lieu of NFPA 25 requirements.

Table RAI B.2.3.16-1.b: New Procedures

Description	NFPA 25 Section	Requirements
Obstruction Investigation		
Obstruction, Internal Inspection of Piping	14.2; 14.3	A new procedure will be prepared and implemented to incorporate the following instructions and requirements for internal inspection of piping and obstruction investigation from NFPA 25, Sections 14.2, 14.3, and subsections. Steps with asterisks have additional clarifying information in NFPA 25, Annex A. The required steps and information are as follows: 14.2: Internal Inspection of Piping. 14.2.1: Except as discussed in 14.2.1.1 and 14.2.1.4 below, an inspection of piping and branch line conditions shall be conducted every 5 years by opening a flushing connection at the end of one main and by removing a sprinkler toward the end of one branch line for the purpose of inspecting for the presence of foreign organic and inorganic material. 14.2.1.1: Alternative nondestructive examination methods [that can ensure that flow blockage will not occur] shall be permitted. 14.2.1.2: Tubercules or slime, if found, shall be tested for indications of microbiologically influenced corrosion (MIC). 14.2.1.3*: If the presence of sufficient foreign organic or inorganic material is found to obstruct pipe or sprinklers, an obstruction investigation shall be conducted as described in Section 14.3. 14.2.1.4: Non-metallic pipe shall not be required to be inspected internally. 14.2.1.5: In dry pipe systems and pre-action systems, the sprinkler removed for inspection shall be from the most remote branch line from the source of water that is not equipped with the inspector's test valve. 14.2.1.6*: Inspection of a cross main is not required where the system does not have a means of inspection. 14.2.2*: In buildings having multiple wet pipe systems, every other system shall have an internal inspection of piping every 5 years as described in 14.2.1 above.

Table RAI B.2.3.16-1.b: New Procedures

Description	NFPA 25 Section	Requirements
		14.2.2.1: During the next inspection frequency required by 14.2.1 above, the alternate systems not inspected during the previous inspection shall have an internal inspection of piping as described in 14.2.1. 14.2.2.2: If the presence of foreign organic and/or inorganic material is found in any system in a building during the 5 year internal inspection of piping, all systems shall have an internal inspection. 14.3: Obstruction Investigation and Prevention. 14.3.1*: An obstruction investigation shall be conducted for system or yard main piping wherever any of the following conditions exist: (1) Defective intake for fire pumps taking suction from open bodies of water (2) The discharge of obstructive material during routine water tests (3) Foreign materials in fire pumps, in dry pipe valves, or in check valves (4)*Foreign material in water during drain tests or plugging of inspector's test connection(s) (5) Plugged sprinklers (6) Plugged piping in sprinkler systems dismantled during building alterations (7) Failure to flush yard piping or surrounding public mains following new installations or repairs (8) A record of broken public mains in the vicinity (9) Abnormally frequent false tripping of a dry pipe valve(s) (10) A system that is returned to service after an extended shutdown (greater than 1 year) (11) There is reason to believe that the sprinkler system contains sodium silicate or highly corrosive fluxes in copper systems (12) A system has been supplied with raw water via the fire department connection

Table RAI B.2.3.16-1.b: New Procedures

Description	NFPA 25 Section	Requirements
		(13) Pinhole leaks (14) A 50 percent increase in the time it takes water to travel to the inspector's test connection from the time the valve trips during a full flow trip test of a dry pipe sprinkler system when compared to the original system acceptance test. 14.3.2*: Systems shall be examined for internal obstructions where conditions exist that could cause obstructed piping. 14.3.2.1: If the condition has not been corrected or the condition is one that could result in obstruction of the piping despite any previous flushing procedures that have been performed, the system shall be examined for internal obstructions every 5 years. 14.3.2.2: Internal examination shall be performed at the following four points: (1) System valve (2) Riser (3) Cross main (4) Branch line 14.3.2.3: Alternative nondestructive examination methods [that can ensure that flow blockage will not occur] shall be permitted. 14.3.3*: If an obstruction investigation indicates the presence of sufficient material to obstruct pipe or sprinklers, a complete flushing program shall be conducted by qualified personnel. [For obstruction investigation flushing procedures, see NFPA 25 Annex D.5.] If loose deposits are identified in the piping, and the evaluation determines that the deposits must be removed, then the piping is required to be flushed repeatedly, in accordance with NFPA 25 Annex D.5, until it is determined that either no deposits are left or that the remaining deposits pose no blockage threat. Areas where excessive deposits are found will undergo more thorough volumetric wall testing to ensure minimum wall thickness is met.

Table RAI B.2.3.16-1.b: New Procedures

Description	NFPA 25 Section	Requirements
		Per NUREG-2191 Table XI.M27-1, the following notes also apply: • Items in areas that are inaccessible because of safety considerations such as those raised by continuous process operations, radiological dose, or energized electrical equipment are inspected during each scheduled shutdown but not more often than every refueling outage interval. • Calibration of measuring and test equipment is conducted in accordance with plant-specific procedures in lieu of NFPA 25 requirements. Additionally, the new procedure will specify that portions of water-based fire protection system components that have been wetted but are normally dry, such as dry-pipe or preaction sprinkler system piping and valves, are subjected to augmented testing and inspections beyond those of NUREG-2191 Table XI.M27-1. The augmented tests and inspections are conducted on piping segments that cannot be drained or piping segments that allow water to collect: • In each 5-year interval, beginning 5 years prior to the SPEO, either conduct a flow test or flush sufficient to detect potential flow blockage, or conduct a visual inspection of 100 percent of the internal surface of piping segments that cannot be drained or piping segments that allow water to collect. • In each 5-year interval of the SPEO, 20 percent of the length of piping segments that cannot be drained or piping segments that allow water to collect is subject to volumetric wall thickness inspections. Measurement points are obtained to the extent that each potential degraded condition can be identified (e.g., general corrosion, MIC). The 20 percent of piping that is inspected in each 5-year interval is in different locations than previously inspected piping. • If the results of a 100-percent internal visual inspection are acceptable, and the segment is not subsequently wetted, no further augmented tests or inspections are necessary.

c. The statements provided in Enhancement 4 (fourth enhancement listed on SLRA page B-153) were not intended to limit the types of changes to be consistent with NUREG-2191, Table XI.M27-1. To clarify, the word "visual" has been removed from the first sentence of this enhancement. This change is shown in the Associated SLRA Revisions section below.

RAI B.2.3.16-1 Request 2:

Procedure 0-OSP-016.30 will be revised to be consistent with GALL-SLR Report AMP XI.M27, and the fire water system AMP basis document will be revised to include this enhancement. Procedure 0-OSP-016.30 will be updated to include the actions required by NFPA 25, Section 7.3.2. More specifically, a hydrant drainage step will be added for dry barrel and wall hydrants and will meet the following requirements of NFPA 25 Sections 7.3.2.4 and 7.3.2.5:

Full drainage [of the hydrant barrel] *shall take no longer than 60 minutes. Where soil conditions or other factors are such that the hydrant barrel does not drain within 60 minutes, or where the groundwater level is above that of the hydrant drain, the hydrant drain shall be plugged and the water in the barrel shall be pumped out.*

RAI B.2.3.16-1 Request 3:

0-OP-016.1 is the fire water system operating procedure. This procedure specifies recommended operating parameters for normal operation of the fire water system, and periodic leak inspections of the fire main. This procedure will be revised to specify periodic monitoring and trending of fire header pressure on a set frequency.

Additionally, procedure 0-ADM-016, "Fire Protection Program," will be revised to include a requirement to ensure that fire water systems are normally maintained at required operating pressure and monitored in such a way that loss of system pressure is immediately detected and corrected when acceptance criteria are exceeded. The monitoring will include periodic fire water system pressure monitoring and trending. The fire water system AMP basis document will be updated to reflect this procedure revision.

RAI B.2.3.16-1 Request 4:

The sprinklers/nozzles for the various plant areas are described below:

- The outdoor transformers use dry-pipe sprinkler systems that utilize open-head Tyco D3 Protectospray Directional Spray Nozzles (or equivalent) per the vendor specification within PTN-3OHM-09-023 and respective transformer drawings. These nozzles are allowed to be cleaned.
- The Units 3 and 4 lube oil reservoirs use dry-pipe sprinkler systems that utilize open-head Viking Model M SSU with Model A-1 Head Guards. These nozzles are allowed to be cleaned.

- The Units 3 and 4 CCW pump rooms (Fire Zone 47 and 54), Auxiliary Building North-South Breezeway (Fire Zone 79A), and Unit 3 Diesel Generator Building Water Curtain use dry pipe sprinkler systems with open head spray nozzles. These nozzles are allowed to be cleaned.
- The Units 3 and 4 EDG Buildings (Fire Zones 72, 73, 74, 75, 133, and 138) and Units 3 and 4 Charging Pump Rooms (Fire Zones 55 and 45) use dry-pipe preaction sprinkler systems that utilize closed head sprinklers. The procedures associated with these sprinklers, listed below, will be updated to ensure any of these sprinklers which are defective are replaced rather than removed and cleaned:
    - 3-SMM-016.02A, "Spray/Sprinkler System Insp. (EDG 3A Preaction Valve 3-10-847 Partial Flow Test, Zone 73 & 75)"
    - 3-SMM-016.02B, "Spray/Sprinkler System Insp. (EDG 3B Preaction Valve 10-844 Partial Flow Test, Zone 72 & 74)"
    - 3-SMM-016.02F, "Spray/Sprinkler System Insp. (Charging PMP Preaction Del. VLVE 3-10-841 Partial Flow Test, Zone 55)"
    - 4-SMM-016.02F, "Spray/Sprinkler System Insp. (Charging PMP Preaction Del. VLV 4-10-830 Partial Flow Test, Zone 45)"
    - 4-SMM-016.02A, "Spray/Sprinkler System Insp. (EDDG 4A Preaction Valve 4-10-1112 Partial Flow Test, Zone 138)"
    - 4-SMM-016.02B, "Spray/Sprinkler System Insp. (EDG 4B Preaction Deluge Valve 4-10-1113 Partial Flow Test, Zone 133)"
- Wet sprinkler systems with closed heads are used in Fire Zone 136 and 141 of the Unit 4 EDG building as well as the turbine building sprinkler systems downstream of the following alarm check valves:
    - 3-10-1302
    - 3-10-1601
    - 4-10-1122
    - 4-10-1302

  The procedure associated with these sprinklers, 4-SMM-016.02C, "EDG XFER PMP 4A&4B Rooms Alarm Check VLV 4-10-1122 Flow Test, Zone 136&141/Sprinkler Inspection," will be updated to ensure any of these sprinklers which are defective are replaced rather than removed and cleaned.

<u>RAI B.2.3.16-1 Request 5:</u>

The procedure referenced in the "Background" and "Issue" sections of this RAI is 0-SFP-016.5, "Fire Protection Equipment Surveillance." Currently, Section 6.9.1 of this procedure states that the threshold for writing a condition report is as follows:

If signs of age related degradation loss of material are evident, it shall be documented in a Condition Report. Engineering shall determine if corrective measures are required.

The acceptance criteria in 0-SFP-016.5 is sufficient for the annual visual inspection of the raw water tank (RWT) exteriors, but for the interior inspections, a new procedure is being created to perform the volumetric wall thickness inspections for the RWTs as shown in Table RAI B.2.3.16-1.b. This new procedure will state that maintaining minimum design wall thickness is the acceptance criteria for the RWT wall thickness inspection. The new procedure will also state that corrective actions (repair/replacement) will be taken if acceptance criteria (minimum wall thickness) are not met or are projected to be exceeded before the next inspection.

Procedure 0-SFP-016.5 will be revised to clarify that the annual visual inspections of the RWT exterior is in accordance with NFPA 25, Section 9.2.5.5, and will be annotated as an SLR commitment.

<u>RAI B.2.3.16-1 Request 6:</u>

Procedure PI-AA-104-1000 is a generic procedure applicable to all AMPs and is used for creating and processing condition reports (CRs). The implementing inspection procedures will include specific acceptance criteria and corrective actions to take when those criteria are not met.

a. With respect to conducting deposit removal evaluations, see the response to RAI B.2.3.16-2.

b. With respect to conducting flushes in accordance with NFPA 25 Annex D.5, see the following associated with "Request 1" of this RAI:

    - Table B.2.3.16-1.a, Item 7.3.2
    - Table B.2.3.16-1.b Items 5.3.1, 14.2, & 14.3

References:

None

Associated SLRA Revisions:

[Response 1.c]

The following changes to SLRA Section B.2.3.16-1 Enhancement 4 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

4. Detection of Aging Effects	Update AMP inspection/testing procedure(s) and develop new procedures to state that testing and ~~visual~~ inspections are performed in accordance with Table XI.M27-1 from NUREG-2191. This table, "Fire Water System Inspection and Testing Recommendations," is based on NFPA 25 (Reference B.3.131), 2011 edition. Unless recommended otherwise, external visual inspections are to be conducted on an RFO interval.

Associated Enclosures:

None

NRC RAI Letter No. ML18218A199 Dated August 6, 2018

RAI B.2.3.16-2

Background:

Many spray or sprinkler system inspection and test procedures (e.g., 4-SMM-016.02A) state that the supply line to the deluge valve should be flushed at normal operating velocity long enough to clear pipe of any scale or foreign materials prior to conducting the test.

During its review of the results of these inspection and test procedures conducted between 2013 to 2017, the staff noted that 16 deluge tests were conducted without any flow blockage of the nozzles being noted; however, there were 5 tests where one or more nozzles were clogged.

Issue:

The staff recognizes that nozzle blockage can occur during testing and a limited number of blocked nozzles might not result in a loss of intended function for the deluge system. However, there are no parameters recorded (e.g., duration of flush, collection and weighing the amount of debris) during the flush. The number of clogged nozzles cannot be used to trend results due to the preconditioning during the flush. As a result, there is no means to trend the test results, as recommended by GALL-SLR Report AMP XI.M27, to determine if an adverse trend is occurring, which could necessitate corrective actions more extensive than cleaning individual nozzles.

Request:

State how the spray and sprinkler system inspection and test procedures will be enhanced to enable trending of data.

FPL Response:

Spray and sprinkler system inspection and test procedures will be revised to enable trending of data. Specifically, the inspection, testing, and flushing procedures listed below will be revised to document and trend deposits (scale or foreign material). Recommended methods for trending deposits may include the following as feasible:

- Inspectors will take photographs of deposits.
- Inspectors will measure the weight of the deposits.
- Inspectors will measure elapsed time taken to complete a flush (i.e., the time required for the flushing water to turn an acceptable color).

The documentation above will be maintained by the AMP owner for comparing and trending inspection/test results.

The inspection and testing procedures listed below will also be revised to include steps to compare the amount of deposits to the previous inspections' results, and if the trend is negative or if the projected solids for the next inspection are anticipated to exceed an acceptable amount that would impact the system intended function, then the PTN Corrective Action Program will be utilized to drive improvement. Additionally, identified deposits will be evaluated for potential impact on downstream components, such as sprinkler nozzles. These procedure changes are in addition to the procedure changes identified in RAI B.2.3.16-1 and impacted procedures include those listed below as well as any new flushing procedures.

0-SMM-016.10	3-SMM-016.02E	3-SMM-016.9	4-SMM-016.02B	4-SMM-016.07
3-SMM-016.02A	3-SMM-016-02F	3-SMM-016.11	4-SMM-016.02D	4-SMM-016.8
3-SMM-016.02B	3-SMM-016.07	4-SMM-016.02	4-SMM-016.02E	4-SMM-016.9
3-SMM-016.02D	3-SMM-016.8	4-SMM-016.02A	4-SMM-016.02F	4-SMM-016.11

References:

None

Associated SLRA Revisions:

No SLRA changes have been identified as a result of this response.

Associated Enclosures:

None

NRC RAI Letter No. ML18218A199 Dated August 6, 2018

RAI B.2.3.16-3

Background:

During the audit, the staff reviewed two 2002 reports associated with the inspection of raw water tank Nos. 1 and 2. These reports stated that: (a) the drainage around the tanks is not adequate to prevent water from coming up over the concrete base and deteriorating the tank base; and b) the base seal will not prevent water from deteriorating the underside of the tank bottom plates.

Issue:

As a result of the potential for water to accumulate under the raw water tanks, the staff has determined that loss of material due to pitting and crevice corrosion could be occurring on the tank bottom. AMP XI.M29 (the recommended AMP for inspection of the bottom surface exposed to soil or concrete of fire water storage tanks) does not include specific recommendations for the quantity of data points or location of the bottom thickness measurements. However, given the potential for water intrusion under the tank, the staff requires this information to complete its evaluation.

It should be noted that the low-frequency electromagnetic testing (LFET) technique can be capable of scanning the entire bottom of the tank in order to detect discrete locations where augmented bottom thickness measurements should be conducted. The staff's evaluation of the use of this technique is documented in NUREG-2172, "Safety Evaluation Report Related to the License Renewal of Callaway Plant, Unit 1," Section 3.0.3.2.8.

Request:

1. State the quantity and location of data points for the periodic bottom thickness measurements of the raw water tanks. In addition, state the basis for why the quantity and location of data points will be sufficient to detect loss of material due to pitting or crevice corrosion.
2. If the LFET technique will be used, state the criteria for followup discrete tank thickness measurements.

If other scanning techniques will be used, state the basis for the effectiveness of these techniques in detecting loss of material due to pitting or crevice corrosion and the criteria for followup discrete tank thickness measurements.

FPL Response:

The carbon steel raw water tanks (RWTs), which are used by the fire water system, will be volumetrically inspected per a new procedure with a method and inspection interval consistent with the relevant portion of NUREG-2191, Table XI.M29-1 shown below.

Table XI.M29-1. Tank Inspection Recommendations[1,2]				
Inspections to Identify Degradation of Inside Surfaces of Tank Shell, Roof[4], and Bottom[5,6]				
Material	**Environment**	**Aging Effect Requiring Management (AERM)**	**Inspection Technique[3]**	**Inspection Frequency**
Steel	Air, condensation	Loss of material	Visual from inside surface (IS) or Volumetric from outside surface (OS)[7]	Each 10-year period starting 10 years before the subsequent period of extended operation
	Raw water, waste water	Loss of material		Each 10-year period starting 10 years before the subsequent period of extended operation
	Treated water	Loss of material		One-time inspection conducted in accordance with GALL-SLR Report AMP XI.M32[8]

Inspections to Identify Degradation of External Surfaces[9] of Tank Shell, Roof, and Bottom				
Material	**Environment**	**AERM**	**Inspection Technique[3]**	**Inspection Frequency**
Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Visual from OS	Each refueling outage interval
	Soil, concrete	Loss of material	Volumetric from IS[12]	Each 10-year period starting 10 years before the subsequent period of extended operation[13]

Table XI.M29-1. Tank Inspection Recommendations[1,2]

1. GALL-SLR Report AMP XI.M30, "Fuel Oil Chemistry," is used to manage loss of material on the internal surfaces of fuel oil storage tanks. However, for outdoor fuel oil storage tanks exposed to soil or concrete and indoor tanks exposed to periodically wetted concrete or exposed to soil, inspections to identify aging of the external surfaces of tanks are conducted in accordance with GALL-SLR Report AMP XI.M29. GALL-SLR Report AMP XI.M41 is used to manage loss of material and cracking for the external surfaces of buried tanks.
2. When one-time internal inspections in accordance with these footnotes are used in lieu of periodic inspections, the one-time inspection must occur within the 5-year period before the start of the subsequent period of extended operation.
3. Alternative inspection methods may be used to inspect both surfaces (i.e., internal, external) or the opposite surface (e.g., inspecting the internal surfaces for loss of material from the external surface, inspecting for corrosion under external insulation from the internal surfaces of the tank) as long as the method has been demonstrated to be effective at detecting the AERM and a sufficient amount of the surface is inspected to provide reasonable assurance that localized aging effects are detected. For example, in some cases, subject to being demonstrated effective by the applicant, the low frequency electromagnetic technique (LFET) can be used to scan an entire surface of a tank. If follow-up ultrasonic examinations are conducted in any areas where the wall thickness is below nominal, an LFET inspection can effectively detect loss of material in the tank shell, roof, or bottom.
4. Nonwetted surfaces on the inside of a tank (e.g., roof, surfaces above the normal waterline) are inspected in the same manner as the wetted surfaces based on the material, environment, and AERM.
5. Visual inspections to identify degradation of the inside surfaces of tank shell, roof, and bottom cover all the inside surfaces. Where this is not possible because of the tank's configuration (e.g., tanks with floating covers or bladders), the SLRA includes a justification for how aging effects will be detected before the loss of the tank's intended function.
6. For tank configurations in which deleterious materials could accumulate on the tank bottom (e.g., sediment, silt), the internal inspections of the tank's bottom include inspections of the side wall of the tank up to the top of the sludge-affected region.
7. At least 20 percent of the tank's internal surface is to be inspected using a method capable of precisely determining wall thickness. The inspection method is capable of detecting both general and pitting corrosion and be demonstrated effective by the applicant.
8. At least one tank for each material and environment combination is inspected at each site. The tank inspection can be credited towards the sample population for GALL-SLR Report AMP XI.M32.
9. For insulated tanks, the external inspections of tank surfaces that are insulated are conducted in accordance with the sampling recommendations in this AMP. If the initial inspections meet the criteria described in the preceding "Alternatives to Removing Insulation" portion of this AMP, subsequent inspections may consist of external visual inspections of the jacketing in lieu of surface examinations. Tanks with tightly adhering insulation may use the "Alternatives to Removing Insulation" portion of this AMP for initial and all follow-on inspections.
10. Not used.
11. A minimum of either 25 sections of the tank's surface (e.g., 1-square-foot sections for tank surfaces, 1-linear-foot sections of weld length) or 20 percent of the tank's surface are examined. The sample inspection points are distributed in such a way that inspections occur in those areas most susceptible to degradation (e.g., areas where contaminants could collect, inlet and outlet nozzles, welds).
12. When volumetric examinations of the tank bottom cannot be conducted because the tank is coated, an exception is stated, and the accompanying justification for not conducting inspections includes the considerations in footnote 13, below, or propose an alternative examination methodology.
13. A one-time inspection conducted in accordance with GALL-SLR Report AMP XI.M32 may be conducted in lieu of periodic inspections if an evaluation conducted before the subsequent period of extended operation and during each 10-year period during the subsequent period of extended operation demonstrates that the soil under the tank is not corrosive using actual soil samples that are analyzed for each individual parameter (e.g., resistivity, pH, redox potential, sulfides, sulfates, moisture) and overall soil corrosivity. The evaluation includes soil sampling from underneath the tank.

    Alternatively, a one-time inspection conducted in accordance with GALL-SLR Report AMP XI.M32 may be conducted in lieu of periodic inspections if the bottom of the tank has been cathodically protected in such a way that the availability and effectiveness criteria of GALL-SLR Report AMP XI.M41, 'Buried and Underground Piping and Tanks'," Table XI.M41-3., "Inspections of Buried Tanks for all Inspection Periods," have been met beginning 5 years prior to the subsequent period of extended operation, and the criteria continue to be met throughout the subsequent period of extended operation.

The new PTN procedure will employ the low-frequency electromagnetic testing (LFET) technique and followup ultrasonic examinations as necessary to implement volumetric inspection of the RWT bottom surface exposed to soil. Because LFET can scan the entire RWT bottom surface, specific data points for bottom thickness measurements are not identified. The new procedure will implement the alternate inspection method as described in Note 3 of Table XI.M29-1 (above) and will effectively detect loss of material due to pitting and crevice corrosion in the RWT tank bottom surfaces.

Since the LFET technique will be used, the criteria for followup discrete tank thickness measurements will be as follows:

> Any regions below nominal plate thickness will have a followup ultrasonic thickness reading. If there are areas of significant loss of material that could impact the pressure boundary function, future ultrasonic thickness measurements and trending will be performed.

References:

None

Associated SLRA Revisions:

No SLRA changes have been identified as a result of this response.

Associated Enclosures:

None

NRC RAI Letter No. ML18218A199 Dated August 6, 2018

RAI B.2.3.16-4

Background:

Procedure FP-AA-1006, "Implementation of the NFPA 805 [Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants] Monitoring Program," describes the plant-specific requirements for implementing NFPA-805.

Issue:

The staff noted that procedure FP-AA-1006 does not cite EPRI Report 1006756, "Fire Protection Equipment Surveillance Optimization and Maintenance Guide." EPRI Report 1006756, Section 11.2, "Data Collection and Evaluation," includes industry-standard guidance for selecting the number of data points to be used in potentially adjusting test and inspection frequencies. Citing EPRI Report 1006756 is not required for subsequent license renewal; however, absent citing a similar standard or enhancing the procedure to incorporate the critical guidance, the staff cannot complete its evaluation. As established by the staff in NUREG-2172, "Safety Evaluation Report Related to the License Renewal of Callaway Plant, Unit 1," Section 3.0.3.2.7, "Fire Water System," the staff requires additional information to complete its evaluation.

Request:

State: (a) the earliest (i.e., number of years prior to the subsequent period of extended operation) data that would be used for modifying test and inspection frequencies; (b) the minimum sample size to modify test and inspection frequencies; and (c) whether performance data would be used to modify fire water storage tank inspections/tests, underground flow tests, and inspections of normally dry but periodically wetted piping that will not drain due to its configuration.

FPL Response:

Procedure 0-ADM-016.7, "Performance Based Optimization Evaluations for Fire Protection," was issued as part of the Turkey Point transition to NFPA 805. Procedure 0-ADM-016.7 incorporates methodology for extending fire protection surveillance frequencies that is consistent with EPRI Report 1006756, NEIL Loss Control Standards, and NRC guidance. The answers to requests a, b and c above are stated below:

a) The data collection guidelines in 0-ADM-016.7 follow the NEIL guidelines for historic reliability calculations. The number of years prior to the subsequent period of extended operations from which data would be collected for modifying test and inspection frequencies is determined based on the current surveillance intervals under evaluation as follows:

   - Surveillances up to quarterly require 2 years of data.
   - Surveillances performed in the range of quarterly up to annually require 3 years of data.

- Surveillances performed in the range of annually up to fuel cycle require 5 years of data.

b) The data collection guidelines in 0-ADM-016.7 include the bounding recommendations for sample size from EPRI Report 1006756. To modify test and inspection frequencies, a minimum sample size of 100 independent samples is recommended. This amount of data will ensure low uncertainty and avoid excessive failure sensitivity. As stated in Reference 1, a sample size of 100 is a desired lower limit, but the analysis can be done with fewer points if a small number of components are involved.

c) The use of performance data to modify surveillance intervals is based on the current length of the surveillance interval. Since fire water storage tank (raw water tank) external visual inspections are currently performed on an annual basis, the interval for these inspections can be changed (lengthened) upon successful evaluation of past inspection results and concurrence by NEIL.

   Performance data will not be used to modify the following surveillances specified in the "Request" section of this RAI, since their prescribed intervals are greater than two times the refueling interval:

   - Raw water tank volumetric and internal tests and inspections.
   - Underground flow tests.
   - Inspections of normally dry but periodically wetted piping that will not drain due to its configuration.

   Procedure 0-ADM-016.7 will be updated to state that the inspections/tests bulleted above are not allowed to have their intervals lengthened.

References:

1. EPRI, Technical Report 1006756, "Fire Protection Equipment Surveillance Optimization and Maintenance Guide," Electric Power Research Institute, Palo Alto, California, July 2003.

Associated SLRA Revisions:

No SLRA changes have been identified as a result of this response.

Associated Enclosures:

None

NRC RAI Letter No. ML18218A199 Dated August 6, 2018

RAI 3.3.2.1.2-1

Background:

SLRA Table 3.3.1, item 3.3.1-064, addresses steel and copper alloy piping and piping components exposed to raw water, treated water, and raw water (potable) which will be managed for loss of material and flow blockage. During its review of components associated with item number 3.3.1-064 for which the applicant cited generic note C, the staff noted that the SLRA credits the Fire Water System program to manage the aging effects for steel, gray cast iron, and copper alloy greater than 15 percent zinc heat exchanger tubes, shell, tubesheet, and channel heads, as shown in the below chart.

Component Type	Material	Environment	AERM
Heat exchanger (tubes)	Copper alloy >15% Zn	Raw water (int)	Loss of material; flow blockage
Heat exchanger (shell)	Gray cast iron	Treated water (int)	Loss of material; flow blockage
Heat exchanger (tubesheet)	Copper alloy >15% Zn	Treated water (ext)	Loss of material; flow blockage
Heat exchanger (tubesheet)	Copper alloy >15% Zn	Raw water (int)	Loss of material
Heat exchanger (tubes)	Copper alloy >15% Zn	Treated water (ext)	Loss of material
Heat exchanger (channel head)	Copper alloy >15% Zn	Raw water (int)	Loss of material; flow blockage
Heat exchanger (shell)	Carbon steel	Treated water (int)	Loss of material

Issue:

The staff lacks sufficient information to conclude which Fire Water System program inspections or tests will be conducted sufficient to detect loss of material and flow blockage for these components.

Request:

State which Fire Water System program inspections or tests will be conducted sufficient to detect loss of material and flow blockage for these components.

FPL Response:

There are two heat exchangers presented in the SLRA for Fire Protection, each associated with the diesel engine for the diesel driven fire pump. One of these heat exchangers cools the diesel engine lubricating oil, and the other heat exchanger cools the diesel water system. The source of cooling water for both heat exchangers is the pumped fluid from the diesel driven fire pump.

FPL determined that the most appropriate line items in NUREG-2191 for the channel head and shell of both heat exchangers were VII.G.AP-197 and VII.G.A-33 for copper and steel (includes gray cast iron) piping/piping components, respectively, which specify the Fire Water System AMP for managing the aging effects. Additionally, VII.G.AP-197 was selected as the appropriate line item for the copper tubes and tubesheet.

Our review determined this selection anticipating that issues associated with these heat exchangers would be identified during surveillance testing of the diesel driven fire pump performed as part of the Fire Water System AMP. However, upon further review of the information for the heat exchanger tubes and tubesheet with respect to NUREG-2191 the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMP will be used for managing the identified aging effects. A revised excerpt of Table 3.3.2-15 is provided below. Some additional minor edits are also included in this revised table.

Per the Table 3.3.2-15 changes, only the copper alloy heat exchanger channel heads and the gray cast iron heat exchanger shells remain within the Fire Water System AMP inspection/testing scope. Since these components are comparable to copper and steel piping, loss of material and flow blockage due to fouling remain the applicable aging effects. These aging effects will be managed by the Fire Water System AMP consistent with other piping and piping components in the fire water system. During our review we found that the entry in the SLRA for a carbon steel heat exchanger shell is not applicable to the fire water system and thus is being deleted.

References:

None

Associated SLRA Revisions:

The following changes to SLRA Table 3.3.2-15 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Table 3.3.2-15: Fire Protection – Summary of Aging Management Evaluation

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-2191 Item	Table 1 Item	Notes
~~Heat exchanger (shell)~~	~~Pressure boundary~~	~~Carbon steel~~	~~Treated water (int)~~	~~Loss of material~~	~~Fire Water System~~	~~VII.G.A-33~~	~~3.3-1, 064~~	~~C~~
Heat exchanger (tubes)	Heat transfer	Copper alloy >15% Zn	Treated water (ext)	Reduction of heat transfer	~~Fire Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.G.AP-187	3.3-1, 042	~~E~~ **A**
Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Treated water (ext)	Loss of material	~~Fire Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.G.AP-197	3.3-1, 064	~~C~~ **E**

Heat exchanger (tubes)	Pressure boundary	Copper alloy >15% Zn	Raw water (int)	Loss of material; Flow blockage	~~Fire Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.G.AP-197	3.3-1, 064	~~C~~ **E**
Heat exchanger (tubesheet)	Pressure boundary	Copper alloy >15% Zn	Raw water (int)	Loss of material; **Flow blockage**	~~Fire Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.G.AP-197	3.3-1, 064	~~C~~ **E**
Heat exchanger (tubesheet)	Pressure boundary	Copper alloy >15% Zn	Treated water (ext)	Loss of material~~;~~ ~~Flow blockage~~	~~Fire Water System~~ **Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components**	VII.G.AP-197	3.3-1, 064	~~C~~ **E**

Associated Enclosures:

None

NRC RAI Letter No. ML18218A199 Dated August 6, 2018

RAI 3.3.2.1.3-1

Background:

SLRA Table 3.3.1, item 3.3.1-042 addresses copper alloy, titanium, or stainless steel heat exchanger tubes exposed to raw water, raw water (potable), or treated water, which will be managed for reduction of heat transfer due to fouling. For the AMR item that cites generic note E, the SLRA credits the Fire Water System Program to manage the aging effect for copper alloy greater than 15 percent heat exchanger tubes.

Issue:

During the in-office audit, the staff was told that there are two diesel engine fire pump heat exchangers associated with several of the SLRA Table 3.3.2-15 AMR items, these being cooling water and a lubricating oil heat exchanger. It was also stated that reduction of heat transfer would be managed by observing heat exchanger performance during the periodic tests of the pump. The staff requires that the information documented in this issue be verified or corrected on the docket.

Request:

Verify that the information as stated in the above issue is correct or state the basis for how the inspections or tests of the Fire Water System program will be effective at managing reduction of heat transfer due to fouling.

FPL Response:

The information as stated in the above issue is correct. Based on the response to RAI 3.3.2.1.2-1, the discussion associated with Item 3.3-1, 042 of SLRA Table 3.3-1 is revised. This change is shown in the Associated SLRA Revisions section below.

References:

None

Associated SLRA Revisions:

The following changes to Item 3.3-1, 042 of SLRA Table 3.3-1 will be made in a future SLRA revision as indicated by text deletion (strikethrough) and text addition (red underlined font).

Table 3.3-1: Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/Mechanism**	**Aging Management Program (AMP)/TLAA**	**Further Evaluation Recommended**	**Discussion**
3.3-1, 042	Copper alloy, titanium, stainless steel heat exchanger tubes exposed to raw water, raw water (potable), treated water	Cracking due to SCC (titanium only), reduction of heat transfer due to fouling	AMP XI.M20, "Open-Cycle Cooling Water System," or AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Consistent with NUREG-2191 for copper heat exchanger tubes with raw water. The Open-Cycle Cooling Water System and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components AMPs are both used to manage copper heat exchanger tubes exposed to raw and treated water. ~~For copper heat exchanger tubes exposed to treated water, the Fire Water System AMP is used where the heat exchanger is associated with Fire Protection.~~ There are no titanium heat exchanger tubes. Stainless steel heat exchanger tubes use a different item (3.3-1, 050).

Associated Enclosures:

None

NRC RAI Letter No. ML18218A199 Dated August 6, 2018

RAI 3.3.2.2.7-1

Background:

SLRA Section 3.3.2.2.7, "Loss of Material Due to Recurring Internal Corrosion," states that there have been no corrosion issues that meet the criteria of recurring internal corrosion.

Issue:

During the Operating Experience Audit, the staff identified several corrective action (CA) entries that might be associated with loss of material due to recurring internal corrosion. During the audit each corrective action entry was discussed and plausible explanations were provided for virtually all examples as to why the cause was not internal corrosion (e.g., external corrosion, leakage past threads, packing leaks). The staff requires that the information be placed on the docket.

Note: in the below request, LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," is cited as the basis for loss of material due to recurring internal corrosion. The recommendations associated with loss of material due to recurring internal corrosion were incorporated into the GALL-SLR Report with no significant changes. As a result, NUREG-2221, "Technical Bases for Changes in the Subsequent License Renewal Guidance Documents NUREG–2191 and NUREG–2192," does not contain the basis for SRP-SLR Section 3.3.2.2.7.

Request:

State the basis for why the following corrective action entries are not examples of internal corrosion as described in LR-ISG-2012-02.

CA Entry	Title	Date
00405413	Leak in weld on 10-inch fire main piping.	04/26/2007
00440984	Small leak in the 1-inch inspector test drain line on the first floor of the nuclear maintenance building in the area of the fire system riser.	05/02/2007
00440545	Through wall leakage in the fire main header.	05/03/2007
00507320	An approximately 2-inch diameter fire line is corroded and leaking at the screwed fitting near a sprinkler head above No. 3 waterbox inlet piping, upstream of drain valve 3-10-1311.	09/12/2007
00462447	Fire water system pipe leak at the raw water storage tank (RWST) in a 2-inch pipe at threaded connection. No visible signs of extensive external corrosion.	01/26/2009

CA Entry	Title	Date
01618249	There is a leak at the connection between the pipe and elbow just downstream of valve 10-619. The leak is a slow drip when in standby and continuous spray when the electric driven fir pump is running.	02/09/2011
01800862	Fire suppression system piping is leaking at a piping union west and above the U3 4A low pressure feed water heater.	09/07/2012
01824738	The 4-10-1301 sprinkler valve just south of the cable spreading room on the mezzanine deck is leaking directly on top of the secondary response center. This is causing mild flooding in the room.	11/17/2012
01824931	A 1-inch pipe with a spray nozzle is broken off of the fire protection loop around the lube oil tank at U4.	11/18/2012
01871471	Water is leaking onto the floor in the response center. The water is coming from the overhead and running down inside the wall, possibly from the fire sprinkler system.	05/02/2013
01877303	Valve 3-10-1303 is leaking externally at a rate of approximately 30 drops per minute (dpm).	05/25/2013
01887603	Action request associated with removing an approximate 3-foot section of 3-inch pipe and replacing it with new pipe. The work area is located in the heating, ventilation, and air conditioning room located on the east side of the building.	07/08/2013
01950652	Through-wall leak on the fire water jockey pump recirculation line. The leak is shooting a 10 to 15 foot stream of water into the air.	03/22/2014
01990890	The deluge fire system just west of the U4 lube oil reservoir has a pin hole leak coming from the joint elbow above valve 4-10-1600. The leak is a constant spray, not drops.	09/12/2014
02021813	Piping near valve 4-10-1600, alarm test valve for U4 turbine building sprinklers, is leaking by a previously installed patch and spraying approximately 1 gallon per minute (gpm). This action request is also linked to 01990890.	01/29/2015
02065087	Valve 4-10-1303, U4 turbine building east sprinkler system sectional isolation valve for the 18-foot elevation sprinklers is leaking at a rate of 200 DPM.	08/05/2015
02124480	Water was noted to be leaking through the lighting fixture in document control. It has been determined that the pipe that is leaking is a fire sprinkler pipe.	04/11/2016
02238434	Repeat leak in recirc. line of diesel driven fire pump	11/30/2017
02235611	Leak in recirc. line of diesel driven fire pump	11/09/2007

FPL Response:

None of the following corrective action entries can be classified as recurring internal corrosion (RIC) as described in LR-ISG-2012-02. The basis for each is described in the table below. FPL will continue to use the corrective action program throughout the lifetime of the plant to determine if recurring internal corrosion is occurring and make program enhancements if necessary. Note that all of the items in the "CA Entry" column are PTN action requests (ARs). The "CA Entry" column name was used for consistency with the RAI request.

Potential Recurring Internal Corrosion Examples

CA Entry	Description	Date	RIC?
00405413	*Leak in weld on 10-inch fire main piping.* This same issue was identified one week later in AR 00440545. Considering that at the time of this AR, there were already multiple patches on the line, this may have been considered recurring internal corrosion. However, since this header's replacement, there have been no further condition reports identifying corrosion on this 10" header.	04/26/2007	No
00440984	*Small leak in the 1-inch inspector test drain line on the first floor of the nuclear maintenance building in the area of the fire system riser.* The leaking sprinkler test drain line associated with this AR is outside of the Power Block. A state licensed fire protection company performed the repair, and there is no evidence that internal corrosion has recurred on this line. Per discussion with the Turkey Point Fire Protection Coordinator: • Currently, there is no procedure governing inspection of non-power block fire protection piping. External visual inspections are performed per NFPA guidance and requirements. If a leak is found, an AR is written to document the issue and repair the leak. • Currently, no internal corrosion inspections are performed for non-power block fire protection piping. Although not an SLR commitment, there is a new requirement for internal corrosion inspections of this piping to occur every 5 years. Turkey Point is planning to implement this requirement later in 2018. The state licensed fire protection company will perform these inspections and make the determinations regarding corrosion issues.	05/02/2007	No
00440545	*Through wall leakage in the fire main header.* This same issue was identified previously in AR 00405413. The AR classifies this as internal corrosion on the 10" firewater main header. Considering that at the time of this AR, there were already 3 patches on the line and a 4th leak was developing, this may have been considered recurring internal corrosion. However, since this header's replacement, there have been no further Condition Reports calling out corrosion on this 10" header.	05/03/2007	No

Potential Recurring Internal Corrosion Examples			
CA Entry	**Description**	**Date**	**RIC?**
00507320	*An approximately 2-inch diameter fire line is corroded and leaking at the screwed fitting near a sprinkler head above No. 3 waterbox inlet piping, upstream of drain valve 3-10-1311.* The photos associated with this AR show external corrosion extending from the tee's threaded connection with the pipe all the way to the sprinkler. This corrosion appears to have initially started from condensation on the joint's threads and got worse as the leak developed.	09/12/2007	No
00462447	*Fire water system pipe leak at the raw water storage tank (RST) in a 2-inch pipe at threaded connection. No visible signs of extensive external corrosion.* The photos associated with this AR show external corrosion and leakage (water spraying) at the threaded connection between an elbow on the Diesel Fire Protection Pump recirculation line and the pipe connected to the RWT. This leaking pipe was replaced by WO 38019021-01. This is not a recurring internal corrosion issue.	01/26/2009	No
01618249	*There is a leak at the connection between the pipe and elbow just downstream of valve 10-619. The leak is a slow drip when in standby and continuous spray when the electric driven fir pump is running.* WO 40068899-01 performed the repair associated with this AR. According to the WO, there was a cracked weld on the elbow. This WO replaced the piping between the elbow and the reducer. The cracking was most likely due to vibrations or thermal fatigue. This is not a recurring internal corrosion issue.	02/09/2011	No
01800862	*Fire suppression system piping is leaking at a piping union west and above the U3 4A low pressure feed water heater.* According to the photos in AR 01800862, the leak is located at a clamped piping joint and is not a through-wall leak. The clamp likely became loose due to thermal or vibration fatigue, or possibly external corrosion at the joint. This is not a recurring internal corrosion issue.	09/07/2012	No
01824738	*The 4-10-1301 sprinkler valve just south of the cable spreading room on the mezzanine deck is leaking directly on top of the secondary response center. This is causing mild flooding in the room.* This AR states that this was a condition where a hose came off a drain section of the fire system that was being drained for maintenance work. The drain hose was restored, and the mild flooding was stopped. The AR states that the valve (hose connection) needs to be repaired so that the hose does not become disconnected. This is not a recurring internal corrosion issue.	11/17/2012	No

Potential Recurring Internal Corrosion Examples			
CA Entry	**Description**	**Date**	**RIC?**
01824931	*A 1inch pipe with a spray nozzle is broken off of the fire protection loop around the lube oil tank at U4.* This piping was already in the process of being replaced by WO 40087742-30, "EPU246905 – Remove Fire Protection Piping." According to the AR 01824931's notes, this fire water piping was already out of service for construction work and during the work activity that the nozzle piping was likely bumped and broke off. The piping associated with this nozzle (downstream of valve 4-10-1590) does not have a history of recurring internal corrosion issues, therefore, this is not a recurring internal corrosion issue.	11/18/2012	No
01871471	*Water is leaking onto the floor in the response center. The water is coming from the overhead and running down inside the wall, possibly from the fire sprinkler system.* WO 40262463-01 was initiated as a response to this AR. The WO is still in "planned" status, but states that the leak was not from the fire water system, but rather the water leaking was from the roof of the break area. A request to pump out the standing water on the roof and seal the penetration was then made. Therefore, this is not a recurring internal corrosion issue.	05/02/2013	No
01877303	*Valve 3-10-1303 is leaking externally at a rate of approximately 30 drops per minute (dpm).* WO 40245985 was initiated as a response to this AR. This WO was later cancelled on September 6, 2013, since the "valve was previously torqued to 20 ft/lbs and for multiple subsequent walkdowns no leakage was observed". Tightening the valve fixed the leak, therefore, this is not a recurring internal corrosion issue.	05/25/2013	No
01887603	*Action request associated with removing an approximate 3foot section of 3inch pipe and replacing it with new pipe. The work area is located in the heating, ventilation, and air conditioning room located on the east side of the building.* This AR states that this issue is related to the cafeteria sprinkler system outside of the power block. A repair was performed by a state licensed fire protection company under WO 40255930-01, and there is no evidence that internal corrosion has recurred on this line. As previously stated above for AR 00440984, although not an SLR commitment, Turkey Point is in the process of incorporating new internal corrosion inspections for non-power block fire water piping. Per discussion with the Turkey Point Fire Protection Coordinator, Turkey Point is planning to implement this requirement later in 2018. .	07/08/2013	No

Potential Recurring Internal Corrosion Examples			
CA Entry	**Description**	**Date**	**RIC?**
01950652	*Through wall leak on the fire water jockey pump recirculation line. The leak is shooting a 10 to 15 foot stream of water into the air.* According to photographs from AR 01950652, the piping in this area has external corrosion due to the outdoor environment and this is the primary cause of the through-wall pinhole leak. The AR shows that this had been temporarily addressed with a sealing clamp, but the piping eventually had to be replaced on February 11, 2015 per WO 40302335-01. This is not a recurring internal corrosion issue.	03/22/2014	No
01990890	*The deluge fire system just west of the U4 lube oil reservoir has a pinhole leak coming from the joint elbow above valve 4-10-1600. The leak is a constant spray, not drops.* The photo associated with this CR shows that external corrosion due to the outdoor environment is the primary cause of this leak at a pipe connection. This CR led to a temporary patch, but when leak occurred again as documented in AR 02021813, the piping was eventually replaced by WO 40366776-01. This is not a recurring internal corrosion issue.	09/12/2014	No
02021813	*Piping near valve 4-10-1600, alarm test valve for U4 turbine building sprinklers, is leaking by a previously installed patch and spraying approximately 1 gallon per minute (gpm). This action request is also linked to 01990890.* Based on the photo from AR 01990890, this issue was primarily due to external corrosion. The piping has since been replaced. This is not a recurring internal corrosion issue.	01/29/2015	No
02065087	*Valve 4-10-1303, U4 turbine building east sprinkler system sectional isolation valve for the 18-foot elevation sprinklers is leaking at a rate of 200 DPM.* The leak was located on valve 4-10-1303. WO 40405794 states that the valve had its packing tightened under WR 94123045. This shows that this was not corrosion related, but rather packing related. Therefore, this is not a recurring internal corrosion issue.	08/05/2015	No
02124480	*Water was noted to be leaking through the lighting fixture in document control. It has been determined that the pipe that is leaking is a fire sprinkler pipe.* This fire protection piping is associated with the administrative building that houses Document Control and is outside of the power block. A state licensed fire protection company, National Fire Protection, LLC, performed the repair as shown in the vendor work order attached to the AR. The vendor replaced a pipe nipple with a socket coupling. There is no evidence that internal corrosion has recurred on this line. As previously stated above for AR 00440984, although not an SLR commitment, Turkey Point is in the process of incorporating new internal corrosion inspections for non-power block fire water piping. Per discussion with the Turkey Point Fire Protection Coordinator, Turkey Point is planning to implement this requirement later in 2018.	04/11/2016	No

Potential Recurring Internal Corrosion Examples			
CA Entry	**Description**	**Date**	**RIC?**
02238434	*Repeat leak in recirc. line of diesel driven fire pump* This issue has been recurring (also note AR 02236802 and AR 02254186) but was determined to be external corrosion due to the outdoor environment. AR 02235611 clarifies that the issue was a hole/crack at an elbow/pipe threaded connection. WO 40570214 performed a temporary fix and shows photographs of the degraded piping and threaded connections due to external corrosion. Additionally, AR 02254186 specifically calls out external corrosion and/or degraded coatings. Therefore, this is not a recurring internal corrosion issue.	11/30/2017	No
02235611	*Leak in recirc. line of diesel driven fire pump* This is the same external corrosion issue as described in AR 02238434 above. This is not a recurring internal corrosion issue.	11/09/2017	No

References:

1. NRC, LR-ISG-2012-02, License Renewal Interim Staff Guidance, Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation, U.S. Nuclear Regulatory Commission, Washington D.C. (ADAMS Accession No. ML13227A361)

Associated SLRA Revisions:

No SLRA changes have been identified as a result of this response.

Associated Enclosures:

None

NRC RAI Letter No. ML18218A199 Dated August 6, 2018

5. Reactor Coolant Pump Flywheel

Regulatory Basis:

10 CFR Section 54.21(c)(1) requires an applicant to provide a list of time-limited aging analyses (TLAAs) and demonstrate that (i) the analyses remain valid for the period of extended operation; (ii) the analyses have been projected to the end of the period of extended operation; or (iii) the effects of aging on the intended functions will be adequately managed for the period of extended operation. One of the findings that the staff must make to issue a renewed license (10 CFR § 54.29(a)) is that actions have been identified and have been or will be taken with respect to managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under § 54.21, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis (CLB). The SRP-SLR provides the acceptance criteria for an applicant to demonstrate compliance with 10 CFR 54.21(c)(1). In order to complete its review and enable making a finding under 10 CFR § 54.29(a), the staff requires additional information in regard to the matters described below.

RAI 4.3.5-1

Background:

The Turkey Point SLR referenced PWROG-17011-NP, Revision 0 report, "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'," dated May 2018 to support the TLAA for the Reactor Coolant Pump Flywheel. The PWROG-17011-NP, Revision 0 report provides the technical and regulatory basis for continuing the 20-year inservice inspection interval approved for reactor coolant pump motor flywheels for the 60 year period of license renewal in WCAP-15666-A into the 80 year period of subsequent license renewal.

Issue:

1. Section 3.4.3 of PWROG-17011-NP, Revision 0 provides descriptions and frequencies of the initiating events for the different conditions listed in Table 3-5. For the second condition, the description is, "The initiating event frequency for a plant trip or non-LOCA transient is estimated as 1 event/year (plants on average experience 1 plant trip per year)." This referencing of a non-LOCA transient does not appear in Tables 3-7 and 3-8 of PWROG-17011-NP, Revision 0 for condition 2. Further, it is contradictory to the description in Table 3-5 of PWROG-17011-NP, Revision 0 and in Tables 3-12 and 3-13 in WCAP-15666-A, which references a LOCA event: "Failure of the RCP motor flywheel given a plant transient or LOCA event with NO loss of electric power to the RCP."

2. Tables 3-7 to 3-9 of PWROG-17011-NP, Revision 0 show that the event frequency for the fourth condition is 1.4E-8/year. In WCAP-15666-A, the corresponding event frequency is 2.8E-8/year based on a maximum LOCA frequency (LOCAs with greater than 5000 gpm blowdown) of 2E-6/year and the probability of loss of station power following a LOCA of 1.4E-2/year. The staff previously approved the value for the fourth condition in WCAP-15666-A. The new event frequency is only half of this previously approved value. The staff needs to confirm the correct value to determine the change in CDF and LERF to verify within the acceptable range in Regulatory Guide 1.174.

Request:

1. Please provide clarification for the inconsistencies between Tables 3-5, 3-7, 3-8, 3-12, and 3-13 regarding LOCA events vs. non-LOCA events.
2. Please justify the difference in the event frequency for the fourth condition between PWROG-17011-NP and WCAP-15666-A.

FPL Response:

1. Table 3-5 of PWROG -17011-NP lists several different conditions that have been identified for potential Reactor Coolant Pump (RCP) motor flywheel failures that are related to its operating speed and potential overspeed under certain conditions. Condition 2 on this listing is "Failure of the RCP motor flywheel given a plant transient or LOCA event with NO loss of electrical power to the RCP." A key attribute of this Condition that pertains to Tables 3-7 and 3-8 is the "NO loss of electrical power to the RCP," as this condition maintains the rpm of the flywheel for the event.

   This condition is carried over to Tables 3-7 and 3-8 as the listed Condition 2, and also considers all transients (both LOCA and non-LOCA) with no loss of electrical power to the RCP. The transient frequency contribution of 1 per year as listed in Condition 2 of Tables 3-7 and 3-8 is intended to subsume the non-large LOCA events. As noted in PWROG-17011-NP, these non-large LOCAs are LOCAs with break sizes of less than 3ft^2. The flywheel performance for these events will be bounded by the design limiting transient. The LOCA contribution is negligible as its frequency contribution is on the order of [0.001] per year and no change in the calculation would result as the frequency remains bounded by 1 per year.

   This Condition 2 in PWROG-17011-NP is also the same as the 'Condition 2' entries in Tables 3-12 and 3-13 of WCAP-15666-A. All entries represent the same conditions and employ the same analysis assumptions.

2. The frequencies of large break LOCA events with break areas in excess of 3 ft^2 (fourth condition) reported in WCAP-15666 were based on Westinghouse fracture mechanics calculations performed prior to NRC issuance of NUREG-1829 (Reference 1). The frequencies of large break LOCA events with break areas in excess of 3 ft^2 estimated in PWROG-17011-NP were updated based on NUREG

1829 and the mean failure rates associated with the larger LOCA break sizes presented in Table 7.19 of this Reference.

Reference 1 states that "The results in Table 7.19 are appropriate to use for PRA applications that separately consider SGTRs." Specifically, in establishing the large break frequency, the 14 inch and 31 inch diameter breaks were extrapolated to 80 years and interpolated to determine a cumulative frequency for a 3 ft^2 break. NUREG-1829 was used as it is consistent with current probabilistic risk assessment practices and associated Regulatory Guide 1.174 submittals.

References:

1. NUREG-1829 Estimating Loss-of-Coolant Accident (LOCA) Frequencies Through the Elicitation Process: Main Report, USNRC, March 2008

Associated SLRA Revisions:

No SLRA changes have been identified as a result of this response.

Associated Enclosures:

None